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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

JOINT PETITION BY THE INDIANA FINANCE)
AUTHORITY ("AUTHORITY") AND INDIANA)
GASIFICATION, LLC ("INDIANA GASIFICATION"))
FOR THE INDIANA UTILITY REGULATORY)
COMMISSION TO (1) APPROVE A SUBSTITUTE)
NATURAL GAS PURCHASE AND SALE)
AGREEMENT ENTERED INTO BY THE)
AUTHORITY AND IG FOR THE SALE BY IG AND)
PURCHASE BY THE AUTHORITY OF SUBSTITUTE)
NATURAL GAS ("SNG") OVER A 30-YEAR TERM)
PURSUANT TO I.C. §4-4-11.6; (2) IF NECESSARY,)
ORDER INDIANA REGULATED ENERGY)
UTILITIES TO ENTER INTO A MANAGEMENT)
CONTRACT WITH THE AUTHORITY; (3) DECLINE)
TO EXERCISE JURISDICTION PURSUANT TO I.C.)
§8-1-2.5-5 OVER IG WITH RESPECT TO ITS)
FINANCING, CONSTRUCTING, OWNING AND)
OPERATING SNG PRODUCTION AND)
TRANSPORTATION FACILITIES, AND AN)
ANCILLARY INTEGRATED COAL GASIFICATION)
POWERPLANT ("ICGP FACILITIES") AND CAUSE)
NO. 43976 ELECTRIC GENERATION FACILITIES)
WHICH USE CLEAN COAL TECHNOLOGY IN)
CONNECTION THEREWITH, AND WHICH)
PRODUCES SNG TO BE SOLD TO THE AUTHORITY)
AND OTHER PERSONS, AND PRODUCES)
ELECTRICITY WHICH WILL BE SOLD TO ENERGY)
UTILITIES; AND (4) GRANT ALL OTHER)
APPROPRIATE AND ASSOCIATED APPROVALS)
AND RELIEF.)

CAUSE NO. 43976

APPROVED: NOV 22 2011

RESPONDENTS: ALL INDIANA REGULATED)
NATURAL GAS LOCAL DISTRIBUTION)
COMPANIES)

ORDER OF THE COMMISSION

Presiding Officers:

James D. Atterholt, Chairman

Angela Rapp Weber, Administrative Law Judge

On December 16, 2010, the Indiana Finance Authority ("IFA" or "Authority") and

Indiana Gasification, LLC (“IG”) (collectively “Joint Petitioners”) filed their Verified Joint Petition and Request For Expedited Treatment (“Joint Petition”) with the Indiana Utility Regulatory Commission (“Commission”) in this matter seeking (1) approval of a substitute natural gas (“SNG”) purchase and sale agreement (“SNG Contract” or “Contract”); (2) if necessary, an Order requiring Indiana regulated energy utilities to enter into a utility management agreement (“UMA”) with the IFA; and (3) declination of jurisdiction over IG.

On January 3, 2011, Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. and Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (collectively “Vectren Energy”) filed a Petition to be a Named Respondent, or, Alternatively, and Intervenor in this proceeding. On January 24, 2011, the Presiding Officers issued a Docket Entry naming Vectren Energy a Respondent in this matter. The Presiding Officers also ordered Joint Petitioners to amend the Joint Petition in this Cause to name each Indiana regulated gas distribution energy utility as a Respondent to this Cause. On January 24, 2011, Joint Petitioners filed an amendment to the caption to their Joint Petition that identified all Indiana regulated natural gas distribution companies as Respondents in this Cause.

On January 24, 2011, the IFA filed its Direct Testimony. IG filed its Direct Testimony on January 25, 2011. On January 26, 2011, Petitions to Intervene were filed in this Cause by the Indiana Industrial Group (“Industrial Group”), whose members are Arcelor Mittal USA, Eli Lilly & Company, and United States Steel Corporation, and Lincolnland Economic Development Corporation (“Lincolnland”). On January 27, 2011, Appearances were filed on behalf of Citizens Gas & Coke Utility and Citizens Gas of Westfield (jointly “Citizens Gas”) and six regulated gas local distribution companies in Indiana: Community Natural Gas Company, Inc.; Midwest Natural Gas Corporation; Indiana Natural Gas Corporation; Ohio Valley Gas Corporation; Ohio Valley Gas, Inc.; and Sycamore Gas Company (“Six LDCs”). On February 2, 2011, Petitions to Intervene were filed in this Cause by four consumer advocacy groups (“Citizens Group”), whose members are Citizens Action Coalition of Indiana, Inc. (“CAC”), Sierra Club–Hoosier Chapter, Spencer County Citizens for Quality of Life, and Valley Watch, Inc. On February 10, 2011, an Appearance was filed on behalf of the Northern Indiana Public Service Co., Kokomo Gas and Fuel Company, and Northern Indiana Fuel & Light Co., Inc. (jointly “NIPSCO”).

On February 10, 2011 the Presiding Officers granted to Petitions to Intervene of the Industrial Group and Lincolnland. On February 17, 2011 the Presiding Officers granted the Citizens Group’s Petition to Intervene.

On March 22, 2011, Lincolnland filed its Case-in-Chief. On March 23, 2011, the Indiana Office of Utility Consumer Counselor (“OUCC”), Six LDCs, NIPSCO, Vectren Energy, and Citizens Group filed their respective Cases-in-Chief. As permitted by Docket Entry dated April 4, 2011, Vectren Energy filed the Direct Testimony of Jerrold L. Ulrey on March 28, 2011. On April 18, 2011, the OUCC, Industrial Group, Six LDCs, NIPSCO, Citizens Group, Vectren Energy filed their Cross-Answering Testimony. On that date, the Industrial Group also filed a Bench Memorandum Regarding the Definition of Retail End-Use Customers. On April 21, 2011, Joint Petitioners filed their Rebuttal Testimony.

Field Hearings were held in West Lafayette, Indiana on April 18, 2011; Jasper, Indiana on April 20, 2011; and Indianapolis, Indiana on April 25, 2011. Pursuant to notice of hearing

given as provided by law, an Evidentiary Hearing commenced in this Cause on May 2, 2011. The parties presented their evidence, and their witnesses were cross-examined at the Evidentiary Hearing.

Having considered the evidence and applicable law, the Commission now finds:

1. **Notice and Jurisdiction.** Due, legal, and timely notice of the public hearings held in this Cause was given and published as required by law. Indiana Code ch. 4-4-11.6 (“SNG Statute”) requires Joint Petitioners to submit the SNG Contract to the Commission for approval. The Commission has jurisdiction over Joint Petitioners and the subject matter of this proceeding.

2. **Joint Petitioners’ Characteristics.** The IFA is a “body politic and corporate” created by Indiana Code § 4-4-11-4. The IFA is not a state agency but an independent instrumentality exercising essential public functions. IG is a special purpose entity and limited liability company created by its ultimate parent company, Leucadia National Corporation (“Leucadia”), for development of an SNG facility in Indiana.

3. **Relief Requested.** IG intends to construct a facility in Spencer County, Indiana that will produce SNG (“SNG Facility” or “SNG Project”). Joint Petitioners request approval of the SNG Contract and all of its terms pursuant to the SNG Statute. They also request the Commission to order, if necessary, all Indiana regulated gas distribution utilities to enter into UMAs with the IFA that will provide for the allocation to their retail end use customers of the proceeds and costs relating to the IFA’s resale of SNG purchased from IG and for billing, collecting, and other services relating to the IFA’s purchase, distribution, and delivery of SNG. They further ask the Commission to decline to exercise its jurisdiction over IG pursuant to Indiana Code § 8-1-2.5-5 as long as IG does not sell electricity or SNG at retail in Indiana.

4. **Joint Petitioners’ Direct Testimony.**

A. **Jennifer M. Alvey.** The Joint Petitioners’ witness, Jennifer M. Alvey, was Chief Executive of the Authority at the time the SNG Contract was negotiated. Ms. Alvey no longer serves in that capacity with the Authority but is testifying on behalf of Joint Petitioners concerning the SNG Contract.

Ms. Alvey testified concerning the Authority’s experience in dealing with complex financial transactions. She also testified about the Authority’s consultation concerning the SNG Contract with the OUCC, outside counsel with expertise in complex financial transactions and energy purchase and transportation agreements, and Shaw Consultants International, Inc. (“Shaw”) regarding engineering and technical due diligence. Ms. Alvey met with several utilities to understand the impact of the SNG Contract on their business. She testified that the Authority also consulted with BP Canada Energy Marketing Corp. after it was chosen to be a third-party marketer of SNG.

Ms. Alvey described the Authority’s understanding of the SNG Statute and goals for the SNG Contract, with the main goal being to enter into an agreement that results in a diversification of Indiana’s natural gas portfolio that will lessen the volatility of the price impact

on customers in Indiana. She generally described the terms of the SNG Contract and attached it to her testimony as Exhibit JMA-1. She explained that the SNG Contract between the Authority and IG, the producer of SNG, has a thirty-year term. Further, Ms. Alvey described the SNG Contract's guaranteed savings in 2008 dollars of \$100 million, which she stated will be passed on to customers over the term of the SNG Contract. If the guaranteed savings has not been realized by the end of the thirty-year term, IG may cover the shortfall in cash. If IG does not cash-fund the difference, the Authority may extend the SNG Contract at a lower SNG price for the same quantities until the savings is realized. Lastly, if the options mentioned do not come to fruition, the IFA may force a sale of the SNG Facility to make up the difference. Ms. Alvey also testified concerning the UMA.

Ms. Alvey testified that the economic development aspects of the SNG Project were secondary but important. The economic development aspects are gigantic because the SNG Facility would be a \$2.5 billion investment, employing 200 people at an average annual compensation of over \$70,000. It could add up to 300 jobs in the Indiana coal industry if Indiana coal is competitively priced. She also testified that the Authority's modeling of the economic result of the SNG Contract indicates that over the thirty-year term of the SNG Contract, the Authority can expect real savings in 2008 dollars of more than \$500 million. In nominal terms, which are what future ratepayers will actually see reflected in their monthly gas bills, Ms. Alvey stated the savings are more than twice that amount, nearly \$1.2 billion.

Ms. Alvey stated the biggest assumption underlying the model and its indications is the assumed future price of natural gas, and the second biggest assumption concerns the assumed future price of coal. Other assumptions in the model include the future price of oil and other products relating to the value of the byproducts of the SNG Facility and ultimately to the amount of net incremental revenue¹ affecting the SNG price.

The Authority's assumptions concerning the future price of natural gas are based on an average of six publicly available forecasts. Given the Authority's skepticism about the prospects for shale gas, it believes that the average of the six publicly available forecasts is likely to be low, and therefore a conservative projection of future natural gas prices. With respect to future coal prices, the Authority used the Energy Information Administration's ("EIA") coal price forecast. The Authority spoke with coal suppliers in a position to meet some or all of the coal needs, and the coal suppliers have verbally indicated prices significantly lower than the EIA's coal price forecast.

Finally, Ms. Alvey provided other reasons why she believes the SNG Contract serves the public interest, including shifting the risk for construction, technology and operations to IG rather than the customers, and the availability to use the \$150 million IG has set aside to return the site to its original state if the SNG Facility's construction is halted or does not result in the production of SNG. She estimated average consumer savings from the prices they will be paying to be in the range of \$3 per customer, per year, for thirty years, based on the guaranteed amount

¹ Net incremental revenue is the aggregate (positive or negative) revenues realized from the sale of incremental SNG, argon, sulfuric acid, rare gases, and other byproducts net of related costs. Shaw Report at 1-3.

itself, and several times higher based on expectations.

B. Reiner W. Kuhr. Reiner W. Kuhr, a professional engineer and Senior Executive Consultant with Shaw, testified on behalf of the IFA. Shaw had been engaged by the Authority as an independent professional engineering and technical advisor to assist with the engineering and technical due diligence in connection with the SNG Project. He said the report prepared by Shaw (“Shaw Report”) outlined, among other things, the key benefits of the SNG Project.

Mr. Kuhr said the Shaw Report concludes that the commercial technologies used by the SNG Project have experienced considerable success, and IG has assembled a competent and qualified project implementation team. The Shaw Report concludes the preliminary project completion schedule should be achievable. Further, he said the Shaw Report also concludes profitability of the SNG Facility will rely on effective management, high plant availability, revenue from a positive Market Differential, and a reasonable operation and maintenance (“O&M”) cost estimate, IG’s demonstrated access to extensive fuel resources, and motivation to maximize productivity and minimize cost. It also recommends that embedded complexities of accounting and reporting be vetted in advance of plant operations. Further, he said the Shaw Report concludes that determining annual O&M plans and budgets should be formalized to provide clarity and understanding in order to adjust the budgets as provided by the SNG Contract’s terms, and fuel procurement needs to be tracked to assure compliance with the purchasing plans.

C. Donald W. Maley. Mr. Maley is a Manager of IG and Vice President in charge of energy investments for Leucadia. Mr. Maley described the underlying structure of the SNG Project as being consistent with a “3Party Covenant” concept, which consists of private capital brought by Leucadia to the SNG Project, a federal guarantee for the long-term debt that will finance up to 80% of the SNG Project’s capital costs, and the SNG Contract approved by the Commission for the sale of the SNG produced.

Mr. Maley testified the SNG Contract’s term roughly matches the term of the debt, with the idea being that the revenue covers the interest and principal payments on the debt. Mr. Maley stated a thirty-year term for the SNG Contract is consistent with regulated utilities’ access to long-term debt markets for thirty-year financing to provide energy services to their customers at predictable prices. He stated consumers would benefit from a thirty-year term on inflation-adjusted terms when compared to volatility in natural gas along with the historical and projected natural gas prices.

The SNG Project is premised on providing a solution to the public policy problem that exists as a result of gas consumers’ 100% exposure to the risk of natural gas market price volatility. According to Mr. Maley, the SNG Project provides a means for diversification of consumers’ gas supply portfolio and for some of their gas to be based on a formula-based pricing mechanism. Approximately 40% of the cost is flat for thirty years (declining in 2008 dollars), 20% is escalated with inflation (flat in terms of 2008 dollars), and 20% is tied to an energy commodity (coal) that has historically demonstrated greater price stability than natural gas. In real dollars, he further noted, the SNG Contract price declines over the thirty-year term where

every expert projection, as well as historical evidence, strongly suggests natural gas prices will increase in real dollars over this period in an erratic, unpredictable, and volatile manner.

Mr. Maley said in IG's Base Case analysis, the thirty-year average real dollar Adjusted Base Contract Price for SNG is about \$6.60/MMBtu. With a thirty-year average market price in the Base Case analysis of over \$7.50/MMBtu and the Market Differential sharing provision of the SNG Contract, Mr. Maley stated the final price of SNG would be around \$7/MMBtu. Although this price is subject to variation based on coal prices and market prices for incremental products, including incremental SNG sold into the natural gas market, it should be more predictable and stable than market natural gas prices.

Mr. Maley described the benefits to Leucadia and IG from investment in the SNG Project. If IG delivers SNG as planned and gas prices turn out to be high, IG can earn a market return or even an above-market return on its capital investment, but only if the consumer has done well at the same time through cumulative savings in real dollars when compared to market prices of natural gas. He said the economic fates of the consumer and IG are directly linked but it is possible for Leucadia to do very poorly while ratepayers do very well. For instance, he said this could happen if gas prices remain very low over the long-term, below even the Low Case projections of the EIA.

He referred to Exhibit DWM-6, which compares the consumer cost/savings under the IG Base Case. Additionally, it illustrates the High Case and Low Case where the market price of natural gas was estimated to be \$2/MMBtu higher and lower, respectively, than in the Base Case estimate. In the Low Case, IG would be stuck with a low, single-digit return on its invested capital, but the consumer is actually much better off than in the Base or High Cases. There is a risk to Indiana consumers from the SNG Contract and a cost they would not incur in the absence of its approval if gas costs are lower than forecasted. However, he also said there is a similar risk to consumers if the SNG Contract is not approved, which is the risk that natural gas market prices exceed price projections, as has consistently occurred in the last decade.

Mr. Maley stated a hedge is an investment that is taken out specifically to reduce or cancel out the risk in another investment. The SNG Project provides a physical hedge of natural gas market prices because it produces the SNG to support the hedge. A purely financial hedge cannot provide the same benefits over a thirty-year term because the associated credit risk is too big. He testified about the benefits of the SNG Project, which include economic development, tax receipts to state and local communities, and keeping Indiana consumer dollars working inside the state rather than exporting those dollars. All of these benefits will still occur even if market prices for natural gas remain low. Mr. Maley described how the SNG Project would be designed, engineered, constructed and operated. He stated the SNG Project will produce a number of products other than SNG, including useful slag. The slag will be available first to the State of Indiana at no cost, and the profit from the sale of all products will be shared with the Authority.

With respect to shale gas production, Mr. Maley expected gas prices from shale gas to increase over the long-term because the investment capital required for shale gas production will decrease unless natural gas prices rise sufficiently to generate the cash flow necessary for shale gas resource development. In any event, Mr. Maley testified the SNG Project is designed to

provide a level of certainty for Indiana's consumers, in terms of both supply and price, in a way that only a coal-based energy project can provide.

In Mr. Maley's opinion, the best time to build is when prices are down. He stated there is a substantial risk the supply and extraction assumptions for shale gas have been exaggerated, and the unit cost of extraction has been underestimated. Just a few years ago, he said, natural gas prices were over \$13/MMBtu, and the common wisdom was that they would stay that high. Now that prices are \$4-\$5/MMBtu, the common wisdom is prices will stay this low. A chief benefit of the SNG Project for consumers, according to Mr. Maley, is in the value of diversifying supply portfolio of natural gas. Mr. Maley expected consumers to save money over the term of the SNG Contract, which is why IG agreed to a \$100 million savings guarantee.

According to Mr. Maley, the SNG Project will be located in Spencer County, Indiana. It has received tremendous support from local governmental officials in the Spencer County area and some helped with the acquisition of the necessary options for this location. He stated it achieves environmental performance superior to traditional coal-fueled energy technologies.

Mr. Maley described the contemplated financing for the \$2.7 billion² SNG Project. IG will invest \$800 million of equity (30% of the SNG Project cost). The approximate 70% balance of the SNG Project will be covered by a loan guarantee from the U.S. Department of Energy ("DOE"). The risk for capital cost overruns would be borne by IG and not the Authority or retail end use customers. IG has the ability to finance the construction, ownership and operation of the SNG Project. The timetable for the financing, construction and commercial production of the SNG Project contemplates commencing construction in the third quarter of 2012, with the first deliveries of SNG to begin in the first quarter of 2016. He said the timeframe is dependent on timely completion of these proceedings, as well as timely receipt of all necessary environmental permitting.

Mr. Maley sponsored several exhibits containing Leucadia's financial information and information relevant to the financing of the SNG Project. The exhibits include Leucadia's 10-Q for the quarter ended September 30, 2010 as filed with the Securities and Exchange Commission ("SEC") (Exhibit DWM-19), a letter from Leucadia regarding its equity commitment of \$506 million or the amount constituting the sum of the expected credit subsidy cost and 20% of the aggregate capital costs to construct and complete the SNG Project (Exhibit DWM-20), and a letter from Citibank expressing the opinion that a federal loan guarantee and the availability of financing from the Federal Financing Bank is critical to obtain debt financing appropriate for the SNG Project (Exhibit DWM-21). He pointed out the Citibank opinion states there are insurmountable hurdles with respect to raising the requisite financing for the SNG Project in today's private bank markets and capital markets due to perceived technological risk and private lenders' aversion to large scale construction projects completed in a project finance structure absent a strong existing banking relationship with a key corporate customer.

Mr. Maley testified IG will not hold itself out as a public utility from which consumers of

² The Commission notes Mr. Maley stated in rebuttal the estimated cost of construction for the SNG Facility is approximately \$2.5 billion. Ms. Alvey described the SNG Facility as a \$2.5 billion investment.

gas or electricity may expect retail sales or distribution services. He stated separate authority from the Commission would be required if it were to engage in retail sales or distribution activities. The structure of the SNG Project departs significantly from a traditional regulated utility framework in ways that benefit the consumer, such as the construction cost overrun risk being borne by the developer and the operating risk upon completion being the sole responsibility of and risk to IG. Mr. Maley further testified that exercise of jurisdiction beyond that requested by the Joint Petition would be an unnecessary burden on both the Commission's resources and on the developers of the SNG Project, the cost of which could only cause cost pressure on the price of the gas. However, he acknowledged that IG expects the Commission to exercise jurisdiction with regard to meeting federal or state pipeline safety standards if they are applicable. Any additional regulatory costs, he said, would also put an unnecessary burden on the qualifying process for a federal loan guarantee which requires the SNG Project to pass the federal government's examination of IG's loan guarantee application in competition with requests for loan guarantees from other applicants.

Mr. Maley described the current status of the federal loan guarantee application and review process. He stated that declination of the Commission's jurisdiction over IG and the SNG Project, except for the granting of such approvals necessary to develop and construct the SNG Facility would be beneficial for retail customers. Other exercise of Commission jurisdiction over the SNG Project would inhibit IG from competing with other providers of functionally similar energy services or facilities. The SNG to be produced is an alternative to other gas sources not regulated by the Commission, except with respect to applicable pipeline safety regulations.

With respect to the incidental electricity to be produced by the SNG Project, Mr. Maley testified the exercise of Commission jurisdiction over IG's rates and charges or financing would similarly inhibit it from competing with other entities that generate electricity solely for wholesale sales to energy utilities. While the SNG Project's primary purpose is to produce SNG and liquefied carbon dioxide ("CO₂") and other non-electricity products, the incidental production of electricity should marginally contribute to extending the useful economic life of existing generation facilities. Mr. Maley said the average electricity output of the SNG Facility at any point in time is expected to be in the range of 250–300 MW, but all but about 13 MW on an annual average will be needed and used for operation of the SNG Facility.

He said the SNG Facility will utilize clean coal technology. The Indiana statutes concerning Commission approval for the use of clean coal technology, as Mr. Maley understood them, do not appear to apply to the SNG Facility. He said the SNG Facility is expected to use Indiana coal as its primary feedstock unless economic considerations or other governmental requirements justify utilization of non-Indiana coal or other feedstock after the technology to be employed in is in place. Any tax credits IG may be entitled to under Indiana law would be reduced by the proportionate use of non-Indiana coal, which provides IG an incentive to use Indiana coal whenever reasonably possible. Based on his understanding of Indiana law, the certification requirement for utility power plant construction also does not apply to the SNG Facility. However, if the statutes apply, he asserted that it would be reasonable for the Commission to grant such a certificate without further regulatory requirements or conditions.

Regarding liquefied CO₂, the SNG Facility will likely produce in excess of five million

tons of liquefied CO₂ per year. Mr. Maley said IG plans to sell liquid CO₂ for use in enhanced oil recovery (“EOR”) to a subsidiary of Denbury Resources, Inc. (“Denbury”) with whom IG has signed a contract for a fifteen-year term with extensions. He testified Denbury’s subsidiary would pay IG on a per-unit basis. The payment terms include a floor price that Denbury would pay for the CO₂, with the price then increasing with the price of oil. According to Mr. Maley, IG plans to ship compressed CO₂ in a pipeline to be built by Denbury, called the Midwest Pipeline, to Mississippi and interconnect with Denbury’s existing CO₂ pipeline network. Mr. Maley asserted EOR is a commercially proven technology, and Denbury indicated it will build the Midwest Pipeline when it has confirmed there will be sufficient CO₂ from two to three projects to support the pipeline economics. He said another scenario in which IG believes the pipeline will be built is with a combination of attractive funding and/or incentives to make the pipeline feasible with just the SNG Facility. Mr. Maley stated the SNG Facility will not be built unless there is an outlet for the CO₂, either through the transportation of it by pipeline for EOR or something similar.

D. William G. Rosenberg. William G. Rosenberg, President of E3 Gasification, LLC, also presented direct testimony on behalf of IG. His research, while serving as a Senior Fellow at Harvard’s Kennedy School of Government, led him and his colleagues to develop a proposal called the 3Party Covenant, whereby the federal government, a state and an equity investor collaborate to attract the investment necessary for capital-intensive and advanced energy technology. While formulating the 3Party Covenant concept, he and his colleagues studied state regulatory programs in several states, including Indiana. After reviewing Indiana laws and processes, they concluded Indiana’s regulatory system was well-suited for a 3Party Covenant project. He said the SNG Project is closely patterned after the original 3Party Covenant concept and was selected by the DOE in July 2009 for due diligence and negotiation of a \$1.875 billion federal loan guarantee. Mr. Rosenberg explained the DOE is well into its due diligence process for this federal loan guarantee, and IG expects to begin negotiating a term sheet in 2011.

Mr. Rosenberg distinguished the structure of the SNG Project from a more traditional utility structure, noting the cost overruns will be paid for by IG and will not be recovered from Indiana consumers. He stated the SNG Project would help Indiana energy security by enabling a new supply of pipeline-quality gas to be produced in Indiana using abundant and secure Illinois Basin coal while also diversifying the natural gas supply in Indiana by utilizing a new clean coal based gas for about 17% of that supply. The SNG supply would not be subject to hurricanes, temperature extremes, supply/demand imbalances, and other market dynamics that have led to significant natural gas price volatility in the past and considerable price uncertainty in the future.

Mr. Rosenberg testified the production of unconventional natural gas resources such as shale, tight gas, and coal bed methane needed to meet the growing natural gas demand has been made possible by technology advancements. Nonetheless, the production for those unconventional gas resources is more costly, more labor intensive, and more capital intensive than historic production of conventional gas. He explained the fracking technologies employed to produce new shale gas supplies have raised considerable environmental concerns and generated additional uncertainty regarding future regulatory oversight and cost implications. Even with the SNG Project, he said, Indiana consumers will remain reliant on volatile natural gas

for over 80% of their supply.

Mr. Rosenberg noted projects that receive a federal loan guarantee must add a budget scoring cost or subsidy cost to the capital costs of the project. The borrower, in this case IG, is required to reimburse the DOE for that cost. A primary driver in determining this subsidy cost is an evaluation of the creditworthiness of the loan and the risk of default. He stated Commission approval of the SNG Contract will substantially mitigate the risk of default and thereby significantly reduce the required payment of the loan guaranty subsidy cost.

Mr. Rosenberg addressed environmental policy implications of the SNG Project's use of coal and petcoke gasification technology for SNG and liquefied CO₂ production. He said this technology enables the beneficial use of coal and petcoke at the same time that many of the environmental issues identified with the combustion of coal are significantly reduced. This result is accomplished because, rather than combusting the feedstock, the coal and petcoke are refined into useful products, including clean-burning SNG and liquefied CO₂ for EOR. Thus, coal gasification will be an important part of the solution for meeting local and national environmental policy objectives of reducing carbon emissions.

Mr. Rosenberg likened the production of SNG from coal and petcoke gasification to the oil refining process that takes a dirty crude oil package and processes it into clean hydrocarbons such as gasoline, kerosene, and heating oil. He stated gasification takes a coal or petcoke package and refines it into clean hydrocarbons such as SNG, liquefied CO₂, sulfuric acid, and other useful products. In the process, the elements of the feedstock not essential to production of SNG are separated out. By converting a significant amount of the feedstock carbon into a 98% pure stream of liquefied CO₂ and selling it for EOR, the SNG Project will not only utilize a state resource as an important part of Indiana's energy future, it will allow the nation to significantly enhance domestic energy security through enhanced onshore domestic oil production. The inherent effectiveness of gasification technology in separating the components of the feedstock results in emissions of traditional regulated pollutants that are, according to Mr. Rosenberg, orders of magnitude below those of combustion processes using similar quantities of coal and petcoke feedstock.

Finally, he testified the SNG Facility is designed to meet its own electric power consumption needs, and recycle, consume, or evaporate all contact process wastewaters. All noncontact cooling water, wastewater, and storm water discharged will meet all applicable state and federal permitting requirements.

E. Arthur E. Berman. Mr. Berman, a petroleum geologist, also presented testimony on behalf of IG. Mr. Berman noted the volatility of natural gas prices over the past decade. He stated the EIA expects cheap energy to characterize the U.S. market for most of the next decade, but over time, the EIA's projections have been unreliable. The major factors that govern natural gas prices are weather, underground storage, and investor sentiment about present and future supply and demand. There is considerable uncertainty about short-term natural gas price projections, and according to Mr. Berman, credible estimates place the price from between \$4.50 and \$8.00 in 2011. He noted that gas projections presented by the *Oil & Gas Journal* and Bernstein Research differ markedly from the EIA's scenario. Mr. Berman stated gas prices will

probably remain volatile and all predictions are uncertain.

The principal natural gas price driver today is shale gas. Mr. Berman described shale as a very fine grain, low permeability rock that is not a conventional reservoir for oil and gas, but has been recognized as a source rock for petroleum since the 1970s. Shale gas is currently estimated to account for about 20% to 30% of total U.S. daily production. He said EIA estimates that shale gas will contribute as much as 45% of the total U.S. supply by 2035. While there may be significant shale gas resources, it is important not to confuse those resources with reserves because resources do not take commercial considerations into account. Mr. Berman stated that resources may be in accumulations so small or deep that the gas may never be drilled or produced at any price, and resource size has been shown to be a poor method of estimating commercial reserves. Eventually, investment and production must rationalize to the commercial realities, which, according to Mr. Berman, do not support the levels of production or profitability from shale resources that many are predicting. He stated the evidence thus far for one of the largest shale resources, the Barnett shale, is that wells decline exponentially, which results in shorter well life and lower reserves than claimed by most operators of shale gas-producing facilities. While other shale plays may have different production characteristics from the Barnett shale resources, he stated it is reasonable to assume that until there is more evidence, these plays will follow a similar pattern.

Mr. Berman indicated natural gas operators require at least \$7.00 per mcf on average to break even in their shale plays. With gas futures below \$5.00 per mcf for the next twelve months (as of the date his direct testimony was filed), currently available hedges fail to guarantee the marginal cost of shale gas production. He further stated that long-term price trends must eventually rationalize to these production cost realities. He determined the cost of shale production from public filings by operators with the SEC and annual reports. For shale gas production to double and reach 45% of the total U.S. supply by 2035, the rig counts for shale gas will have to more than double. Mr. Berman believed this cannot happen unless natural gas prices rise substantially beyond EIA predictions regardless of improvements in drilling efficiency and economies of scale.

In his opinion, the necessary level of gas prices to support natural gas production from shale, as well as conventional resources, will be at least \$7.00 per mcf. If shale reserves are overstated, this rate would be even higher. Mr. Berman testified that at the very least, it is reasonable to assume considerable uncertainty in shale gas reserves and costs because there is insufficient production history upon which to base future production decline trends and well life.

Mr. Berman recommended the Commission approve the SNG Contract because he believes it is important to base long-term plans on multiple sources of energy and to base present and future plans on project economics that have a secure historical base. Mr. Berman stated shale gas economics involve considerable uncertainty that is likely to persist for several years. He recommended assigning appropriate risks to shale gas reserves and costs and seeking diverse sources of energy.

F. John L. Weiss. Mr. Weiss, a Vice President of the mining and geological consulting firm John T. Boyd Company ("Boyd"), testified on behalf of IG concerning the

security of feedstock supply for the SNG Project, IG's expected feedstock procurement plans and alternatives for the SNG Project. He assisted IG in its feedstock procurement plans, including the evaluation of historical and current mining operations throughout Indiana and the Illinois Basin. He testified that the projected feedstock requirements for the SNG Project of nearly 3.5 million tons ("Mt") per year equates to slightly more than 100 Mt of coal consumption over thirty years. He noted the SNG Facility's location provides an opportunity to optimize the balance between minimum feedstock supply costs and maximum reliability of supply, while achieving relatively low levels of operational and financial risk. He also stated there are significant undeveloped blocks of coal reserves in proximity to the Spencer County site, which is within acceptable hauling distance from active coal mining operations throughout Indiana. Mr. Weiss testified the site's proximity to virtually all the coal production in Indiana, as well as in Illinois and western Kentucky, will be beneficial in promoting competition among not only the regional coal producers, but also the trucking and rail entities that transfer coal from active mines to end users. Additionally, the site's location on the Ohio River will enable IG to procure coal via low-cost barge transportation.

IG's feedstock supply considerations are comparable with those of major coal-fired electricity generation stations that consistently procure significant levels of coal from Illinois Basin mines, according to Mr. Weiss. He stated the coal reserves in the Illinois Basin are massive and could support substantial increases in annual output for many decades, and the mining conditions throughout the Illinois Basin are well understood. He noted that production in the Illinois Basin declined sharply in the 1990s as a result of the Clean Air Act amendment reducing the demand for high-sulfur Illinois Basin coal, but that regional production is rebounding in conjunction with the widespread addition of scrubbers at coal-fired power stations. Mr. Weiss did not expect environmental opposition to curtail the growth of future coal output from the Illinois Basin. While he did not expect any abatement of organized opposition on the part of environmental special interest groups toward mining activities, he stated the Illinois Basin is generally regarded as being coal friendly in comparison with other major U.S. coal basins.

Current coal producers in the Illinois Basin have sufficient coal reserves to allow production to be maintained and increased for many decades. Mr. Weiss further testified public and proprietary reports from major coal producers indicate that the current reserve estimates thirty years of production at current output; the availability of Illinois Basin reserves is not a concern for IG because there are also significant coal resources that have not yet been consolidated into logical reserve blocks. The EIA reports there are ten billion tons of coal reserves in Indiana, which is ten times the reported reserves of active Indiana coal producers. This suggests Indiana alone has sufficient coal reserves to last nearly 300 years at the current annual production rate. Mr. Weiss stated these reserves could easily meet decades of coal supply requirements from existing consumers and many projects similar to the SNG Project.

Neither the reported reserves of current producers, nor the EIA figures are appropriate for evaluating regional reserves, according to Mr. Weiss. He noted the actual reserves are probably not as great as the EIA estimates but are more than the figures reported by regional producers who understate the extent of reserves. This discrepancy exists because significant mineral rights remain in the hands of individuals, non-mining corporations, municipalities, cooperatives, etc., and those properties have never been assembled in logical controlled mining blocks. Also, he

noted the financing arrangements and coal contract requirements rarely require coal producers to document control of coal reserves that extend beyond a ten- to fifteen-year range. As a result, regional mine operators have traditionally had little incentive to invest in a procurement of coal reserves that will not be mined for twenty years or more.

With regard to future production of coal, Mr. Weiss anticipated the vast coal reserves remaining within the Illinois Basin will provide favorable development opportunities especially when compared to other eastern U.S. coal basins. Potential new mines in the Illinois Basin have a larger base of reserves, lower capital investment requirements, and shorter lead times to production. According to Mr. Weiss, future coal production from the Illinois Basin will predominantly be sourced from historically disadvantaged high-sulfur reserves, which tend to have thicker seams and better mining conditions, higher productivity, and lower costs than those of Appalachian producers.

Mr. Weiss acknowledged it is often presumed that the most cost-effective location for a coal consumer is immediately adjacent to its supply, but that few coal-fired plants in the United States have been built on the basis of placing supply reliance on a single, dedicated bituminous coal reserve. He was not aware of any assembled and uncommitted blocks of coal reserves within Indiana with proven economic viability that could, on a stand-alone basis, support IG's thirty-year feedstock requirements. Further, he stated the ability to procure coal from multiple sources reduces feedstock supply risk, and the competition among multiple suppliers will be advantageous to IG's overall feedstock costs. He stated that, compared to a mine-mouth site, the combination of many established local producers, existing production capacity, regional coal reserves, and an efficient transportation network offers a better foundation for a logical and cost-effective feedstock supply plan for IG over a thirty-year period.

Mr. Weiss testified it would not be difficult for IG to obtain the necessary feedstock supply for its proposed SNG Project because there are many active mines and proposed mines that have significant coal reserves and are capable of high annual production volumes and long operating lives. However, he noted it would make sense for IG to pursue control of coal reserves for its own use and procure strategically located coal reserves by fee ownership, lease or other acceptable forms of control. Mr. Weiss said IG could seek to control sufficient recoverable reserves to supply the majority of its consumption for a minimum of five years. Such reserves would provide it with a competitive backstop when faced with coal market situations where demand for coal exceeds available supply and drives the price up. In the event of high coal prices, he stated IG also would have the option of developing its own production capacity and thereby reduce its average delivered cost of coal and minimize the risk of production shortfalls during periods of limited coal availability.

Mr. Weiss testified that while it is generally preferable to obtain coal from the closest coal producer to minimize transportation costs, having the ability to transfer coal from numerous sites is also a significant benefit. The availability of multiple transportation systems—road, rail and river—to the Spencer County site will provide access to virtually all coal producers in the Illinois Basin. This will enable IG to minimize the transportation component of the overall delivered price of its feedstock supply. Additionally, he noted the availability of secure coal from various entities using any or all three of these transport options increases the diversity of

potential suppliers, thus reducing the risk of supply disruptions due to operating problems at any single coal producer.

Most coal buyers purchase the vast majority of their coal requirements under long-term contracts, rather than on the spot market, and under a portfolio of contracts of varying terms to allow efficient planning. Mr. Weiss testified contracts are typically executed at market prices, but they lock in the price for coal for extended time periods, thereby providing predictability in coal supply costs. He said a buyer may also purchase additional coal for immediate usage on a short-term basis, representing the spot market where coal is priced at spot market prices. These prices, he stated, are not indicative of the average coal price paid by utilities.

Mr. Weiss stated there are many coal contracting strategies that are used to compensate for variations in the short- and intermediate-term market prices for coal. For example, supply contracts of up to three years are often signed at fixed, but not necessarily flat, prices. Longer-term coal contracts typically have re-opener provisions that partially adjust the contract price toward the then-current market price, generally subject to a cap and/or floor price. He stated re-opener provisions are almost always required in long-term coal contracts because the industry has been unable to develop indices that both producers and consumers are willing to accept as a basis for price beyond a five-year horizon. A coal consumer will usually have several coal supply arrangements of varying length and vintages with multiple producers to reduce the buyer's market exposure in any given year. This method of laddering coal contracts results in the average price of coal having less volatility than the market, and the average price is generally lower than the market price. Mr. Weiss noted this may not always be the case, however, and in a rising market price environment, the average price paid for coal purchased via portfolio coal contracts will generally be below the market price. In a stable or declining environment, he said the average price of multiple contracts could be higher than the prevailing market price. He explained why he believes it would be a risky strategy for a large coal buyer to allow contracts to expire and purchase all coal at a lower spot market price when prices are declining and gave examples.

With regard to petroleum coke, or petcoke, Mr. Weiss testified this is produced from the residual bottom-of-the-barrel heavy oil obtained from the oil refining process. This high carbon, low hydrogen byproduct is coked to yield a lighter, more valuable product. Approximately 69% of the nation's crude oil refining operating capacity is equipped with cokers, and approximately 62% of the total domestic petcoke production capacity is located in the states along the Gulf of Mexico. Mr. Weiss testified Boyd expects significant increases in future petcoke production capacity as refineries invest in expansions of coking output and/or the installation of cokers at refineries that are not producing petcoke.

G. George P. Gruber. Mr. Gruber is a Vice President and Technology Manager for gasification, syngas, and synfuels for Black & Veatch Corporation. He testified on behalf of IG concerning the technology and design to be employed for the SNG Facility as they relate to production of SNG, CO₂, and the associated environmental implications.

Mr. Gruber described all of the physical facilities to be used for the production of SNG by the SNG Facility, the nature of the engineering work done to date, and the plan for continuing

activities leading to construction. The physical facilities are planned to be in three locations. The coal and coke barge unloading, Ohio River intake structure, and raw water pump station will be located on approximately thirty acres adjacent to the Ohio River 1.13 miles from the main plant. The gasification plant will be built on ninety-seven acres, and the coal and coke storage and rail loop will be located on 133 acres adjacent to the gasification plant. He said enclosed conveyors will transfer coal and coke from barge unloading to storage and from storage to the feed bins for each rod mill in the gasification plant.

Mr. Gruber described in detail the location of the SNG Facility and stated why that location is appropriate from a design, engineering and operational standpoint. He noted it will be located near the Ohio River and the town of Rockport. Mr. Gruber stated this location is appropriate because it provides adequate land, has an adequate water supply from the nearby Ohio River, coal and coke feedstock can be delivered by barge, rail, and truck. Also, the SNG product can be transported by nearby natural gas pipelines, electricity high voltage interconnections can be made nearby, and the location is compatible with extension of the existing liquid CO₂ pipeline delivery system.

Site work for the SNG Facility is forecasted to start seven months after Commission approval of the SNG Contract and receipt of all required permits. He further stated the SNG Facility's construction is forecasted to start thirteen months after receipt of the SNG Contract approval and permits. Mr. Gruber testified that after the SNG Facility is constructed, the mechanical completion, commissioning and start-up of the SNG Facility will be in stages. After all the utilities and air separation areas are operating reliably, the process areas will be started up in sequence beginning with coal/coke grinding and slurry.

Mr. Gruber described the difference between feasibility and front-end engineering design ("FEED"). Feasibility evaluations and studies are performed during early project evaluation to screen feedstocks, products, technologies, plant configurations, and other pertinent aspects of the project leading to a conceptual plant design and design basis. He said the FEED further defines the project to provide a firm basis for engineering, procurement and construction contracts.³ The SNG Facility will be designed to process 100% coal as well as blends of coal with petcoke containing up to 49% petcoke by weight. Additionally, Mr. Gruber described the energy efficiency differences between these two feedstocks and how they can be blended. He said the SNG Facility is expected to be able to support sales from 42–47 billion Btu per year. But, SNG production will depend on performance characteristics of the purchased equipment, operation of the equipment, feedstock quality, ambient conditions, and ability of the customers to take the SNG product.

With regard to electricity generation, he said the SNG Facility will produce steam from process cooling, which will allow condensing steam turbines to generate up to 300 MW of

³ Mr. Gruber noted that documents produced during the FEED typically include equipment layout drawings, equipment data sheets and specifications, preliminary civil engineering drawings, sketches of foundations and structural steel, piping diagrams, electrical one-line drawings, plant system diagrams, etc., all of which must be sufficient to produce material requirements, and pricing, and an estimate of construction costs.

electricity at design plant capacity. Mr. Gruber stated the net electricity from the SNG Facility, with all byproduct CO₂ compressed for EOR, is estimated to vary from -15 to +37 MW, depending on coal composition and cooling water temperature. The clean coal technology to be utilized by the SNG Project is similar to that used in other gasification facilities and will control sulfur dioxide ("SO₂") emissions to less than 0.1% of the sulfur in the coal feed. He further stated this is an extremely low level achieved without greatly increasing the SNG Facility cost compared with conventional emissions reduction facilities, which are limited to controlling SO₂ emissions to 2% to 5% of the sulfur in the coal feed and have a higher cost per ton of SO₂ removed. The SO₂ emission control facilities for the SNG Project will not be add-on pollution control devices like the processes required for reduction of pollutants from conventional power plants. He also stated New Source Performance Standards will be applicable to the SNG Project.

SNG export to sales will flow through an on-site metering station for measurement of flow and heating value. Mr. Gruber further noted the SNG pipeline is planned to connect to the nearby NGPLA thirty-inch diameter Midwestern Gas Transmission natural gas pipeline. Alternative interconnection options also exist for connecting to the ANR natural gas pipeline. The SNG Project's electricity interconnect is planned to be the nearby Vectren Energy 138 KV transmission line, and according to Mr. Gruber, alternative interconnection options also exist for connecting to Hoosier Energy transmission facilities.

Mr. Gruber also explained how the production of liquefied CO₂ will work at the SNG Facility. He noted the production of CO₂ will be fully implemented as an integral part of the gasification-to-SNG process and commence simultaneously with the start of commercial operation of the SNG Facility. Separation of an isolated stream of pure CO₂ is an inherent part of the SNG production process because achieving the syngas composition needed to produce SNG requires separation and removal of the CO₂. Compression of the CO₂ into a fluid is necessary for the transportation of the CO₂ through a pipeline. He stated the SNG Facility is in essence a combined SNG and CO₂ production facility.

According to Mr. Gruber, the SNG Project will have low SO₂ emissions because of the high sulfur removal efficiency of Rectisol and the high sulfur conversion efficiency of the wet sulfuric acid process. Mr. Gruber noted that methanol will be used for gasifier start-up, which will result in very low flare emissions, and the sulfuric acid process will have selective catalytic reduction of nitrogen oxide, a hydrogen peroxide scrubber and a high efficiency mist separation which will control nitrogen oxide, SO₂ and sulfuric acid mist emissions. The auxiliary boiler will have ultra low NO_x burners with flue gas recirculation or equivalent best available control technology for nitrogen oxide emissions control. Mr. Gruber testified that the regenerative thermal oxidizers (RTOs) will oxidize 99% of the CO and methanol and 98% of the H₂S and COS in the CO₂ stream. Mr. Gruber stated all process wastewater will be treated in a zero liquid discharge, evaporator-crystallizer system that produces salt and recovers the water for reuse in the gasification process.

5. OUCC Direct and Cross-Answering Testimony.

A. Ralph Miller. Mr. Miller, an independent consulting economist, testified on behalf of the OUCC. In 2007, he participated as a consultant to the OUCC in negotiations relating to an earlier proposal by IG to sell SNG to several Indiana gas utilities, a proposal

generally similar to the SNG Project. Mr. Miller testified that although most of the gas supply arrangements used by gas distribution companies do not involve long-term commitments, some of them do, and he has been called upon to examine those long-term arrangements.

Regarding his role in the process by which the SNG Contract was developed, Mr. Miller testified that the Indiana Code provides for the IFA to consult with the OUCC before negotiating and entering into the SNG Contract. In October 2010, the OUCC retained him to assist in that consultation. At the time he was retained, the IFA and IG had negotiated a term sheet for an SNG purchase contract, but the IFA had not yet provided a draft of such contract to the OUCC. Mr. Miller testified the OUCC asked him to review the term sheet and provide an initial evaluation of the proposed SNG Project in the context of the SNG Statute.

Mr. Miller identified several possible issues with the term sheet and areas in which he suggested that the OUCC obtain additional information from the IFA about its due diligence and other efforts in negotiating the term sheet and the SNG Contract. He then participated in conferences between the IFA and the OUCC, at which time his concerns were discussed and satisfactorily addressed. Early in December 2010, the OUCC sent him a draft of the SNG Contract subsequently received from the IFA, which he reviewed and found that it addressed to his satisfaction possible issues that he had identified in the term sheet. He stated he has also reviewed the executed version of the SNG Contract.

Mr. Miller stated the most important features the SNG Contract should provide to Indiana customers are diversification of the energy supply; limitation of the risk Indiana customers may pay more for SNG than the market price of conventional natural gas supply; and protection against the danger that Indiana customers will have a continuing obligation to purchase SNG without assurance that any such SNG supplies would be forthcoming. Mr. Miller stated the SNG Contract addresses each of these important issues. The SNG Contract provides for a diversification of the supply of natural gas for Indiana customers. SNG from coal is also diversification relative to the way most coal is used for electric generation because it does not involve conventional combustion, which is the principal issue with the use of coal as fuel. According to Mr. Miller, the guaranteed savings of \$100 million protects against some of the danger that the price of the SNG to Indiana customers will exceed the market price of conventional natural gas supplies.

The primary protection for Indiana customers against having a continuing obligation to purchase SNG even if no SNG is produced is the “Long Stop” date of December 31, 2018 in the SNG Contract. Mr. Miller stated that if IG fails to complete the proposed SNG Facility and the commercial production of SNG by the Long Stop date, the Authority has a unilateral right to terminate the SNG Contract on thirty-days notice. The Long Stop date is subject to extension only for delays beyond June 30, 2011 in completing the present proceeding, and specifically not for delays associated with force majeure. IG has seven years and six months to complete its SNG Facility and bring it online with commercial production, and the Authority can terminate the SNG Contract if this deadline is not met.

In the absence of significant competition among prospective sellers for the opportunity to provide SNG to the Authority, Mr. Miller noted neither the IFA nor the representatives of

Indiana customers can know whether the terms of the proposed SNG Contract represent the market price for this type of SNG purchase agreement.

Regarding the absence of competition among prospective sellers of SNG to the Authority, Mr. Miller noted the Authority issued a request for proposals (“RFP”) in March 2009. IG submitted its proposal two weeks later, and the IFA did not receive any other responses. Mr. Miller observed that the only opportunity for competition in this procurement process was the two-week period for responding to the RFP at the end of March and beginning of April 2009, and he noted no competition appeared at that time.

Mr. Miller said Mr. Maley’s testimony indicates the pricing formula may yield a positive return to IG even if natural gas prices are so low that SNG is more expensive to produce than natural gas. This does not mean that IG is guaranteed a profit under the SNG Contract. Mr. Miller states that under the SNG Contract, IG—not Indiana customers—bears the risk that the construction costs of the SNG Facility will exceed IG’s estimate (but IG reaps the gain if the construction costs are less than estimated). IG also bears the entire risk that the SNG Facility will not produce the 38 million MMBtu per year that the IFA is committed to purchase if it is produced, and there is no gain to IG if the SNG Facility produces less than 38 million MMBtu. IG shares with Indiana customers the risk that revenues from additional products and the production of an amount of SNG greater than 38 million MMBtu per year will fail to reach expectations. Mr. Miller stated the SNG Contract thus appears to shield IG from much of the risk of low natural gas market prices, but it does not protect IG against the risk of the construction and operation of the proposed SNG Facility.

The SNG Contract provides incentives for IG to manage the SNG Project to maximize the benefits for Indiana customers. Mr. Miller stated that IG has a direct financial incentive to maximize the production of SNG and additional products and to do so at a minimum incremental cost because it retains a substantial percentage share (generally 50%) of the net revenues from all these activities, with the balance going to the Authority for distribution to Indiana customers. IG also has a financial incentive to control the costs that are reflected directly in the SNG price. He explained IG is at risk for the \$100 million of guaranteed savings if the SNG prices exceed or are close to the price of natural gas and because there is a cap on the amounts that can be included for Changes in Governmental Requirements.

According to Mr. Miller, the terms of the SNG Contract ensure the benefits of the SNG Project go to the Indiana customers that bear the risk of loss if the SNG Project fails to achieve the expected benefits. IG and Indiana customers will share the expected benefits, with each attaining a larger benefit as the total amount of benefits available for sharing increases. This sharing of benefits occurs because the SNG Contract provides for sharing Net Incremental Revenues of the SNG Project, which are the principal source of the expected benefits of the SNG Project.

Mr. Miller expressed concern that some customers could opt into sharing the benefits of the SNG Project if those benefits are positive, but opt out of sharing in any losses. The SNG Statute provides that the IFA can pay any net benefits from its SNG activities to retail end use customers, and then recoup any losses from these customers. If it is possible for some entities to

choose to be retail end use customers as defined in the SNG Contract only when the IFA is distributing benefits, and not when recouping losses, those entities would be able to obtain any benefits provided by the SNG Contract without bearing the risk of any losses.

The UMA proposed by the IFA defines retail end use gas customers to exclude industrial transport customers with an annual volume of 50,000 dekatherms or more ("Exempt Customers"). Exempt Customers will not be included in the class of retail end use gas customers at any later point in the term of the SNG Contract. Mr. Miller stated that large industrial gas use customers are thus exempt from the sharing of risks and benefits at the beginning of the SNG Contract's term, when it is most likely that benefits will be negative, but they cannot later opt into the sharing arrangement if benefits become positive.

Mr. Miller testified it appears that an entity can withdraw from the class of retail end use customers by discontinuing its use of natural gas, and it can join this class by becoming a gas customer. Entities that now use gas can thus avoid any negative consequence under the SNG Contract by ceasing their use of gas, and they can obtain a share of any positive benefits by becoming a gas customer.

However, Mr. Miller viewed these possibilities as a positive feature of the SNG Contract and not a problem. The factor most likely to cause a negative result from the SNG Contract is low gas prices. There is little danger that entities will stop using natural gas when it is relatively inexpensive merely because they must help pay for any negative result of the SNG Project as part of their gas bills. Similarly, large positive benefits from the SNG Contract are most likely to be a consequence of high natural gas prices, and there is again little danger that entities will migrate from other fuels to gas at a time when gas is expensive merely to share the benefits from the SNG Project.

The SNG Contract protects against the risk of large increases in the price of SNG that might occur because of increases in the SNG costs, or for other reasons such as regulatory and public policy changes. Mr. Miller stated that the Authority negotiated a pricing formula for SNG in which all but two of the components are capped or subject to other controls. These caps and controls protect against unlimited increases in the price the IFA pays for the SNG it purchases. Two price components that are not capped or subject to other controls are the Pipeline Transportation Charge and the pass through of New Taxes. The Pipeline Transportation Charge is a very small fraction of the total SNG cost or price, and the transportation services required for the SNG Project are subject to regulation by the FERC. According to Mr. Miller, the absence of a cap on the Pipeline Transportation Charges is not a significant concern.

Mr. Miller testified the only New Taxes that are passed through to the SNG price without a cap are new or increased taxes that apply specifically to the production of SNG, including taxes such as carbon taxes or Btu taxes that apply to fuels and energy products. The New Taxes category is limited in scope because it encompasses only governmental actions that constitute taxes in a narrow sense of the word. He testified that Changes in Governmental Requirements is a separate category of government actions, and its effect on the SNG price is capped.

Within the category of taxes, changes in general business taxes are excluded from being

passed through to the SNG price. Taxes on additional products are also excluded and treated instead as offsets against Incremental Revenues in the determination of Net Incremental Revenues. Taxes on additional products can therefore reduce the amount of the credit (i.e., the reduction in the SNG price) from Net Incremental Revenues, but they cannot increase the SNG price to an amount higher than it would be absent any additional products. Mr. Miller also observed that negative net CO₂ revenues can increase the SNG price (and CO₂ is also an additional product) but this increase is capped at \$0.51 per MMBtu.

Mr. Miller testified the O&M component is fixed at \$1.88 per MMBtu plus adjustments for inflation and specified price indexes, with a provision for redetermination to reflect IG's actual O&M expense per MMBtu at five-year intervals starting the seventh year of production. IG cannot request a redetermination unless it has achieved cumulative savings by selling SNG to the IFA at lower prices than the market price of natural gas. The provision prevents IG from including O&M costs in the SNG price unless the SNG price has been low enough to provide gas cost savings to Indiana customers.

The fuel component of each month's price per MMBtu of SNG is 96.5% of the actual delivery cost per MMBtu for the coal (or petcoke) used in that month, and multiplied by a reciprocal of the actual conversion efficiency achieved by the SNG Facility in that month. The reciprocal of the conversion efficiency is the ratio of the total quantity of fuel used in the month (measured in MMBtu) to the total quantity of SNG produced in that month. Mr. Miller stated that this multiplier is limited to a maximum of 2.5 initially, decreasing to 2.0 after 20 months, and that the fuel component of MMBtu of SNG is thus limited to 1.93 times the actual delivered cost of fuel per MMBtu.

Mr. Miller observed that there is no cap on the actual delivered cost of fuel per MMBtu of fuel used in the SNG Project or on the inclusion of the actual delivered cost of fuel per MMBtu in the SNG price. The most appropriate way to view the arrangement, according to Mr. Miller, is that it substitutes the delivery cost of the coal (or petcoke) for the market price of natural gas as the primary driver for part of the natural gas requirements of Indiana customers.

Lower natural gas prices may be a real possibility, but Mr. Miller does not view the possibility of low natural gas prices as a "danger" or reason for not approving the SNG Contract, even if it would be more expensive for Indiana customers than natural gas in the situation of low natural gas prices. He stated the proposed SNG Contract is most appropriately viewed as insurance against the risk of high natural gas prices. The purchase of insurance is not rendered undesirable by the possibility that the events being insured against may not occur. He stated it would be shortsighted to reject this insurance against the risk of high natural gas prices for fear that it would involve some net additional costs if gas prices remain low throughout the term of the SNG Contract. Mr. Miller noted that the risk of high natural gas prices is recognized by the SNG Statute.

According to Mr. Miller, the SNG Contract protects Indiana customers against the risk that the proposed SNG Facility will fail to operate as planned or at an irregular rate. The IFA is protected against expected normal fluctuations in SNG output because IG cannot receive credit for any Incremental Production of SNG in any month unless the IFA has received its full

allotment for the month. The IFA is protected against any major shortfall in SNG production because it pays only for the SNG that it receives. Mr. Miller stated IG has no other sources of revenue to replace shortfalls in SNG production and therefore has a very strong financial incentive to keep its SNG Facility operating as planned.

Mr. Miller testified that a risk exists that the selling price of the SNG will be slightly less than current monthly or spot market price of conventional natural gas supplies if the supply of SNG produced is less reliable on a daily basis than conventional natural gas supplies. If so, the marketer has to sell the SNG production at a discount from the published indexed prices for natural gas. However, this discount would be relatively small because the SNG production would most likely be more reliable than contractually interruptible gas supplies and could be firmed up at relatively low cost by an entity with access to gas storage.

Under the SNG Contract, any reduction of the selling price for the SNG reduces the positive Market Differential (or increases the negative Market Differential) because the Market Differential is the difference between the actual selling price of the SNG and the SNG price chargeable to the IFA before adjustment for a positive or negative Market Differential. The IFA and IG therefore share the risk of obtaining only a discounted selling price for the SNG production, and the IFA's share is passed through to Indiana customers.

Mr. Miller also testified the SNG Contract imposes no reliability requirements on IG for daily or monthly production from quantities of SNG and no notice requirements on IG for changing the daily or monthly rate of SNG production. He observed that prospective purchasers of the SNG may view it as less reliable than conventional natural gas supplies until the SNG Project has established a record for which its reliability can be determined. He said this risk did not affect his overall assessment of the merits of the SNG Contract. The magnitude of the SNG sale price risk is a small fraction of the price of natural gas and is also small relative to the other risks and uncertainties affecting the SNG Project. This relatively small risk is one of the factors that he considered in his evaluation, but it was not large enough to sway his assessment from one side to the other. Mr. Miller testified it would be appropriate for the IFA, IG and the prospective marketer, to attempt to mitigate this risk when developing the marketing and services agreement.

Finally, Mr. Miller testified that the SNG Contract is a reasonable implementation of the objectives and requirements set forth in the SNG Statute, satisfies the explicit requirements of the SNG Statute, and its terms and conditions are designed to achieve the legislative objectives. He noted the IFA took appropriate steps to initiate procurement of SNG, negotiate a contract for purchasing that SNG under reasonable terms and conditions, and obtain a favorable contract. Mr. Miller concluded the IFA was successful in achieving these objectives.

Mr. Miller testified in his cross-answering testimony that it is not important for the Commission to determine which natural gas price forecast is best or most likely, but instead the Commission should try to identify a range within which future gas prices are likely to occur and then make judgments about the likely range of possible net benefits or net losses to Indiana customers from the SNG Contract. The IG Base Case natural gas price forecast is within a range of reasonably likely future natural gas prices, and the forecasts projecting much lower natural gas prices are based on the expectation there will be an enormous expansion of shale gas production

at costs of around \$5.50 per Dth or less.

Mr. Miller noted that Vectren Energy's witness Mr. Ulrey referenced a Bipartisan-Clean Skies Report ("Clean Skies Report") in support of his view, but this exhibit also emphasizes that there remain large uncertainties that cloud this rosy outlook.

Mr. Miller said the purpose of a hedge is to protect against the uncertainty or variability of the cost of an underlying transaction that will be made sometime in the future. A perfect hedge will yield a gain if the actual future cost of the underlying transaction turns out to be at the high end of its possible range, and the hedge will yield a loss if the actual future cost of the underlying transaction is at the low end. Mr. Miller concluded the uncertainty about the eventual amount of gains or losses for the SNG Contract's hedge is the essence of the hedge, not something that detracts from its purpose.

B. Tyler E. Bolinger. Mr. Bolinger, Director of the OUCC's Electric Division, presented only cross-answering testimony for the OUCC. Mr. Bolinger testified Vectren Energy has conflicts of interest between shareholders and ratepayers because it purchases coal from an affiliate, which, according to Mr. Bolinger, undermines its credibility as an advocate for ratepayers. Mr. Bolinger suggested Vectren Energy might have been more supportive of the SNG Project if its location did not lend itself to a highly competitive coal procurement process.

6. Vectren Energy's Direct and Cross-Answering Testimony.

A. Stephen L. Thumb. Stephen L. Thumb, a Principal employed with Energy Ventures Analysis, Inc. ("EVA"), provided testimony, including a report (the "EVA Report"), related to the development of shale gas and its long-term implications on gas reserves and prices.

Mr. Thumb testified concerning his report. The EVA Report states, "The unprecedented growth in shale production over just the last few years is due to a combination of the prolific nature of the shale plays and the rapid increase in industry drilling activity for these plays, as they, for the most part, represent the best well economics in the U.S." EVA Report at 2-3 to 2-4. He said according to the EVA Report, the Potential Gas Committee ("PGC") in its last bi-annual report estimated that technically recoverable reserves for shale gas are 40% of estimated technically recoverable reserves for the Lower-48. The EIA increased its "assessment of the shale reserve potential in the U.S. from 480 TCF to 827 TCF, or 72% higher than it estimated in 2010." *Id.* at 2-8. Mr. Thumb testified factors in the expansion of shale gas include the huge aerial extent of the shale play and superior well economics, the latter deriving from improvements in drilling technology.

Mr. Thumb testified the EVA Report summarizes the opinions of other industry participants, first related to breakeven prices. The median breakeven price was \$3.90/MMBtu with acreage, and \$3.56/MMBtu without acreage. The aggregation of industry data supported the conclusion that the development of the major shales is commercially viable at gas prices below \$6.00 per MMBtu and, in most cases, below \$5.50 per MMBtu. He said according to the vast majority of the industry, "game changing" shales will be an important new source of natural gas

supply, growing from 3% of that supply in 2003 to 45% over the long-term.

Mr. Thumb again cited industry consensus that natural gas prices will be below \$7.00/MMBtu in constant dollars for almost all of the next two decades. The increased shale production has lowered price volatility, collapsed basis differentials, altered the strategic approach of the industry to high-volume, low-margin, destroyed the economics of regasification plants, and caused world natural gas prices to decline. Related to the power sector, Mr. Thumb attributed the cancellation of nuclear plants, the accelerated retirements of coal plants and the lack of progress on renewable facilities to the impact of shale gas. He stated the EVA Report notes that long-term contracts from producers may be increasingly available and that the traditional relationship between oil and gas prices has fundamentally changed.

Mr. Thumb testified Mr. Berman's testimony misconstrues the prolific nature of the shales and their economic viability. Also, Mr. Berman is mistaken on the current nature of gas price volatility. Mr. Thumb stated Mr. Berman uses an outlier price projection, the 2012 forecast of Bernstein Research, to present a view on future gas prices that is far from the industry consensus. The EVA Report disputes Mr. Berman's belief in natural gas price volatility, stating the shale phenomenon has caused a fundamental change in such volatility, and also asserting that Mr. Berman has ignored coal price volatility. Mr. Thumb also testified Mr. Berman's negative characterization of the EIA is without basis.

Regarding well economics, Mr. Thumb noted the EVA Report states Mr. Berman ignored advances in technology, advancement in best practices for shale development and the advantage of going forward economics, which exclude sunk costs, all of which will continue to improve well economics. Additionally, the EVA Report states Mr. Berman should not include debt costs in calculating the cost of production because debt service is one of the components of the cost of capital, and including it represents double accounting. Mr. Thumb stated gas industry technical assessments provided by others challenge Mr. Berman's analysis of the Barnett shale play, and Mr. Berman's exclusion from his analysis of the concepts of the marginal producer and the statistical effect poor producers have on raw data. The EVA Report states the best operators attain results 40% or more, better than the average operator and four to five times that of the poor producers. Mr. Thumb also disagreed with Mr. Berman's comparisons between the various shales because of the unique characteristic of each shale play.

Mr. Thumb noted the EVA Report states, "Mr. Berman's assertion that exploration and production require a payout in two to three years for an economic project is incorrect." *Id.* at 5-9. It disputed his statement that there is broad agreement that natural gas operations require at least \$7.00/mcf to break even. Finally, he said it concludes Mr. Berman was an outlier in the industry, citing an article entitled "How Arthur Berman Could Be Very Wrong."

Mr. Thumb testified that current reported events related to ExxonMobil, Seneca Resources and Range Resources show continued strong production at low cost, while Morgan Stanley has forecast long-term natural gas prices holding at or near \$5.50/MMBtu.

B. Ronald Norman. Ronald Norman, a Member of the Management Group and Energy Capital Markets practice at PA Consulting Group, Inc. ("PA"), evaluated the

expected range of potential benefits and costs to customers under the proposed SNG Contract. In addition, he evaluated the extent to which the SNG Contract hedges natural gas price risk for Indiana customers.

Mr. Norman described the economic features of the SNG Contract, highlighting the \$150 million Consumer Protection Reserve Account ("CPR"), the \$100 million guarantee of savings, the possibility of cost increases due to New Taxes or Changes in Governmental Requirements, and the provisions for sharing Market Differentials. He explained the impact of the sharing provisions on Indiana customers can be most easily understood by assuming a scenario where the CPR has been exhausted, and IG has received an aggregate amount equal to the CPR Commitment Amount. In this scenario, Indiana customers pay 100% of any negative Market Differential, but receive only 50% of any positive Market Differential. Effectively, Mr. Norman stated, Indiana customers must pay for all of the losses under the SNG Contract, while only enjoying 50% of the benefits.

Mr. Norman provided Exhibit RN-2, which depicts the impact on customers in 2008 dollars and the net present value results if the natural gas market price over the SNG Contract term is \$1, \$2, \$3 and \$4 per MMBtu above and below the SNG price. For example, he said his analysis shows that if the market price for natural gas were \$2 per MMBtu above the adjusted SNG price, customers would enjoy net present savings of \$314 million. Conversely, if natural gas prices were \$2 per MMBtu below the SNG price, customers would incur net present value losses of \$658 million.

Mr. Norman testified the Base Case customer savings of over \$500 million referenced in the testimony of Mr. Maley and Ms. Alvey is a real or inflation-adjusted value expressed in 2008 dollars. Mr. Norman stated although accounting for inflation, by using real dollars, is appropriate in many analyses, investors typically evaluate long-term investments or contracts using a net present value analysis, particularly when there is a significant difference in the timing of expenditures and expected returns. This type of analysis uses a discount rate to adjust for the fact that a dollar in the future is worth less than a dollar today. Mr. Norman stated a net present value analysis allows one to examine the value of an investment of this type, discounted back at the investor's cost of capital or rate of return hurdle.

Mr. Norman stated regulated utilities typically make investment decisions based on the opportunity to earn a return at their weighted average cost of capital ("WACC"). He observed that because Indiana gas customers are likely to view the SNG Contract as if it is an investment to be made by their utilities, a representative utility WACC of 7.5% based on recent Commission gas utility Orders is a reasonable discount rate to use for this analysis. When discounted to present value using this discount rate, the \$500+ million of 2008 dollar savings identified by Mr. Maley and Ms. Alvey is reduced to \$150 million. Mr. Norman explained that the present value is smaller than \$500 million because IG's estimate accounts only for inflation. He said an investor will not be satisfied by the return of a dollar years later without some kind of return. Mr. Norman asserted the SNG Contract provision providing IG with a 12% rate of return on any additional capital employed by IG to comply with Changes in Governmental Requirements is analogous to the WACC applicable to regulated Indiana gas utilities.

Mr. Norman explained IG also used a High Case and a Low Case, which employ different natural gas price forecasts than the Base Case. He presented Exhibit RN-4 to illustrate the market price of natural gas for the three cases. He said this exhibit illustrates the substantial dollar differences that arise from making these adjustments, as represented graphically for IG's Base Case in Exhibit RN-3.

Mr. Norman testified he used two models to analyze the value of the SNG Contract to consumers, what he terms a proforma model and a stochastic model. He explained his proforma model is based on the hard copy model provided by IG. His stochastic valuation methodology involves simulating the prices of the underlying commodities, in this case natural gas and coal, using recent historical information from the relevant forwards/futures markets. In particular, the methodology involves examining the volatility (essentially the uncertainty) of the commodity prices, and determining the extent to which the price of one commodity (e.g., natural gas) is correlated with the price of another commodity (e.g., coal). Mr. Norman testified once the volatilities and correlations are understood, the long-term price forecasts for each relevant commodity are adjusted, for the duration of the SNG Contract, to simulate a potential path of monthly commodity prices (a run). Mr. Norman said each run represents a possible path for future prices, subject to the expected volatility and correlation of prices, and several thousand runs are generated to develop a distribution of possible outcomes. According to Mr. Norman, the average across all the paths matches the underlying long-term price forecasts for each commodity.

Mr. Norman identified the major factor driving the value to Indiana consumers as the future market price of natural gas, along with the future market prices for coal and petroleum coke. He also added that byproduct sales, specifically the disposition of CO₂ from the SNG Project, and the sharing provisions in the SNG Contract are also important in the analysis.

Mr. Norman made three changes in his proforma model relative to the IG model to correct what he considered to be minor errors in IG's modeling: (1) modification of the assumed amount of byproduct sales during the first two years of the SNG Facility's operations, to reflect the fact that it is expected to be operating below its ultimate production of 47.2 million MMBtu per year in those years; (2) modification of the gas transportation costs to increase with inflation; and (3) addition of revenues from the sale of power to Incremental Revenues which are subject to the SNG Contract's sharing provisions. Additionally, based on the testimony of Ms. Medine, he eliminated the use of petcoke as a feedstock and used 100% coal.

Mr. Norman identified alternative natural gas price forecasts to those employed in IG's model, as reflected in Exhibit RN-7. In Exhibit RN-8, Mr. Norman showed the positive and negative savings from using each of six different natural gas price forecasts: IG Base Case, IG High Case, EVA, NYMEX curve (extrapolated), EIA, and a combination of NYMEX and EIA. Only IG's Base Case and High Case showed positive results. In Exhibit RN-9, Mr. Norman illustrated the effect of using NYMEX pricing and IG Base Case gas pricing. Using NYMEX prices results in very large negative Market Differentials in the early years of the SNG Contract, with the CPR being exhausted in less than twenty-four months and nearly \$500 million in negative savings accumulated at the end of ten years. Mr. Norman testified the very large positive savings values projected after 2030 in IG's Base Case are not large enough in present

value terms to offset the initial negative savings and still result in a small negative net present value for customers.

Mr. Norman presented Exhibit RN-10, which takes his Base Case assumptions and shows certain sensitivities related to the sale of incremental SNG production (i.e., production above the 38,000,000 MMBtu contract amount) and byproduct sales, as well as sharing of costs related to changes in various regulations. His Base Case assumptions include IG's coal forecast; the natural gas forecast provided by Mr. Thumb; IG's performance, operating efficiency and operating cost assumptions; IG's assumptions about prices and quantities for byproduct sales and a fuel use of 100% coal, based on the testimony of Ms. Medine. He said this Case results in a net present value cost to Indiana customers of \$470 million. His other Cases reflect modification of one of the key contract assumptions to illustrate the impact of that single assumption. He testified these modifications include a 50% reduction in byproduct sales (increases costs \$200 million), increasing variable O&M costs (results in small increases in costs), and the inability to monetize the CO₂ tax credits and sell CO₂, coupled with a requirement to dispose (increases costs by \$250 million). He concluded savings estimates are critically dependant on the natural gas forecast, with exposure to customers also resulting from differences in byproduct sales and actual cost of operating the SNG Facility.

Mr. Norman quantified the impact of the fuel price risk through his stochastic modeling approach. The expected cost of the SNG Contract to Indiana customers using PA's assumptions is approximately \$1.7 billion in 2008 dollars over the market price natural gas. At the 80% lower confidence level, PA's analysis shows Indiana customers could be required to pay up to \$4 billion in 2008 dollars more than they would pay if they purchased at the market price of natural gas. Mr. Norman testified these results are based on assumed fuel price forecasts provided by Vectren Energy expert witnesses and show a wide distribution of potential outcomes, 75% of which contain a value less than the savings guarantee of \$100 million. Mr. Norman stated this indicates a high probability that the \$100 million savings guarantee will not be realized through the thirty-year term.

Mr. Norman combined his analysis of natural gas and coal price volatilities with IG's Base Case gas and coal price forecasts and performed the same analysis. He stated his results are savings of \$150 million in 2008 dollars, which is substantially lower than the \$500+ million savings that the IFA and IG witnesses referenced in their testimony. He concluded from his analysis that most of the calculated savings occur late in the thirty-year term. Furthermore, at the 80% lower confidence level, PA's analysis using IG's Base Case gas and coal price forecasts shows that the SNG Contract could lose up to \$2 billion in 2008 dollars. He concluded that in approximately 50% of the simulated results of his analysis, the \$100 million savings will not be realized under IG's Base Case assumptions once the volatilities of coal and gas prices are factored into the analysis.

Mr. Norman acknowledged that because coal prices are not perfectly correlated with natural gas prices, there will be some reduction in overall price uncertainty faced by Indiana gas customers with the SNG Contract in place. However, he testified the wide distribution in potential outcomes under either his Base Case (Exhibit RN-11) or IG's Base Case (Exhibit RN-12) illustrate customers face substantial uncertainty regarding the potential price they would pay

under the SNG Contract. He explained the basic idea of a hedge is to reduce the variability in possible outcomes. Although the SNG Contract reduces price uncertainty to some degree, it is not a particularly effective hedge. He concluded gas buyers could purchase an equivalent volume of natural gas using NYMEX forward contracts, through 2023, and essentially eliminate all natural gas price uncertainty over that period.

C. **Emily Medine.** Emily Medine, a Principal of EVA, provided testimony regarding price volatility in the coal and petcoke markets and the potential use of Indiana coal by IG. Ms. Medine testified that demand for Illinois Basin coal has been increasing as a result of the retrofit of scrubbers on significant generating capacity in the eastern U.S. to comply with state and federal environmental regulations. She also testified there is consensus that there are sufficient reserves within the Illinois Basin for the SNG Facility. She disagreed with Mr. Maley regarding the volatility in coal prices. She stated in the last ten years, coal price volatility has significantly increased, which is a change from the period prior to 2001 when coal prices were relatively stable.

There is no liquid index for Illinois Basin coal, and Ms. Medine stated prompt and forward prices for Illinois Basin coal, however, are typically reported by traders and publications. Ms. Medine testified prompt prices reflect the current market price for delivery in ninety days; forward prices reflect the current market price for delivery in longer future periods. Ms. Medine said prompt prices for Illinois Basin coal almost doubled in 2001, plunged in 2003, increased again in 2005, fell in 2007 and then almost tripled in 2008. She stated in 2009 prices fell again, but have since rebounded somewhat. These increases in price volatility are expected to continue and perhaps intensify as solid fuel plans move to the margin for many utilities. In other words, as natural gas generation moves ahead of coal in dispatch, many coal plants will no longer be base-loaded and, as a result, have variable burns. She said the coal delivery system is set up to be as ratable as possible and volatile demand would most likely make pricing more volatile as well. The export market is also affecting volatility as supply tightens during those periods of high demand.

Ms. Medine testified IG and the IFA are currently using an average delivered coal price forecast obtained from the EIA related to the 2011 Annual Energy Outlook (“AEO”) for the delivery of coal from the East Interior supply region to the East North Central demand region. Ms. Medine reviewed this forecast and found it to be reasonably similar on average to EVA’s forecast. However, she did not believe the EIA long-term coal price forecast captures price volatility.

Ms. Medine stated petcoke is a byproduct of the coking process that many refineries employ to maximize production of lighter transportation fuels. Petcoke production is driven by crude oil and refined product prices. Ultimately, the supply of petcoke is a function of oil demand and crude oil quality. Because the incremental oil supply is expected to come from heavier and sourer crudes, coking capacity is expected to be added, and petcoke production will increase. Ms. Medine testified that there are several types of petcoke. Fuel grade petcoke is coke that can be used in place of coal. Currently, and for the foreseeable future, exports account for the largest share of production because refineries have found the highest value market to be in the global market.

Unlike coal, there is no long-term equilibrium price tied to production costs and no liquid forward price index for petcoke. Her experience in the current market is that except for spot purchases, refineries are pricing petcoke using the Pace Index, which provides price ranges for certain qualities and origins of petcoke. The transaction prices generally are the index (low, mid, or high) plus or minus a base differential. Ms. Medine said she is unaware of any new petcoke sales at fixed prices on a multi-year basis.

Ms. Medine stated petcoke prices peaked in mid-2008 and plummeted as a result of the global economic recession. The rebound in petcoke prices, however, has been more pronounced than it was for coal. These prices have effectively returned to peak levels. Ms. Medine further noted many North American utilities have reduced or eliminated petcoke from their fuel blends, and the utilities continuing to purchase petcoke are paying very high prices.

The EVA developed a forecast of petcoke delivered to the Rockport, Indiana location. Ms. Medine stated the EVA outlook for petcoke prices is ultimately capped at its alternative, which is the price for coal at the marginal plant. The price for U.S. petcoke will continue to be set by the global market price for coal. Ms. Medine stated this means two things for petcoke prices delivered to IG. First, petcoke pricing will be based upon the global price of petcoke adjusted for any transportation savings/costs to Rockport. Second, petcoke prices are expected to continue to be very volatile, which cannot be addressed in a ladder procurement strategy.

If petcoke is a fuel source, the likely origin of the petcoke would not be Indiana because the only refinery producing petcoke in Indiana is on Lake Michigan. She stated the more logical source of petcoke would be Conoco Philips' refinery at Wood River, Illinois. Ms. Medine said her petcoke price forecast is substantially higher than the price forecast provided by Jacobs Consultancy ("Jacobs"), which is the basis of IG's and the IFA's assumptions. She believed the fundamental difference is that Jacobs treated the Midwest petcoke market in isolation rather than recognizing the ability to export this product through the U.S. Gulf as is currently occurring. Ms. Medine said the petcoke that could be delivered to IG could also participate in the export market.

Indiana coal is unlikely to be the primary source of supply to the SNG Facility. The Rockport site will have barge delivery, which she believed will be the primary if not the exclusive means of delivery of coal. Ms. Medine stated that all parties appear to recognize that truck delivery for the entire SNG Facility's requirement is not feasible. She said Mr. Maley generally states Indiana coal would be the source of supply to IG. IG's witness Mr. Weiss never addresses the question of state of origin. Rather, Mr. Weiss speaks of the reserve base in Indiana and the entire Illinois Basin as being more than adequate for IG's coal requirements. Ms. Medine stated Mr. Weiss recognizes that the Ohio River site chosen by IG is more likely to result in use of non-Indiana coal than Indiana coal when he states "many coal producers in southern Illinois and western Kentucky ship coal to customers in barges on the Ohio River," notably excluding Indiana coal.

Ms. Medine testified a review of coal purchases by the Ohio River-served plants in Indiana indicates that less than 5% of the coal delivered to the barge-served Indiana plants on the Ohio River originates in Indiana. The results are similar for Kentucky. She further testified the

only plant that is receiving more than half of its coal from Indiana is Cane Run, which she believed receives its Indiana coal by rail. Most Indiana coal moves to Indiana power plants that receive it by rail and/or truck. In 2010, Indiana coal comprised 86% of purchases by these utilities, and further, these utilities accounted for 75% of Indiana coal production.

If IG connects with the Norfolk Southern Railroad (“NS”), the potential for Indiana coal would be higher. Ms. Medine also stated, however, only a handful of Indiana coal mines load on the NS, thereby requiring at least two-line hauls for most Indiana coal producers. Two-line hauls are generally more expensive than single-line hauls. Ms. Medine noted that according to the NS website, only three mine complexes in Indiana are served directly by the carrier, and one mine is served by the Algiers Winslow and Western Railroad, which is owned by NS. These four mines produced less than 8 million tons of coal in 2010. Two of those mines produce most of the coal, which is low-sulfur coal that receives a premium in the market, making them, according to Ms. Medine, unlikely to be a source for IG.

Ms. Medine testified utilities that have invested in barge unloading capability on the Ohio River generally find it to be a more attractive option than rail or truck. The small number of high-sulfur Indiana coal mines on the NS railroad limits the likely competitiveness of rail delivery versus barge delivery. Ms. Medine also stated the location of the SNG Project and what is known of its planned infrastructure would heavily favor use of Illinois Basin coal from other states and potentially give such states a price advantage on a delivered-cost basis.

D. Jerrold L. Ulrey. Jerrold L. Ulrey, the Vice President of Regulatory Affairs and Fuels for Vectren Utility Holdings, Inc., provided an overview of concerns regarding the SNG Contract and related arrangements. Mr. Ulrey indicated the SNG Contract would need to satisfy all statutory requirements and be determined to be in the public interest.

Mr. Ulrey stated that generally the SNG Contract is a financial arrangement whereby customers receive a credit on their bills to the extent that actual SNG prices are below actual market prices and incur additional charges if SNG prices are above actual market prices. Mr. Ulrey summarized the requirements of the SNG Statute, focusing on the role of the Commission’s approval. The SNG Statute requires the Commission to scrutinize the provisions of the SNG Contract to ensure that the arrangement will be in the public interest. Mr. Ulrey acknowledged there are potential benefits, including the likely use of coal within the Illinois Basin, which could potentially include the use of Indiana coal, and the potential to spur economic activity through jobs for construction, maintenance, and operations, in addition to possible coal jobs. Mr. Ulrey testified that while such benefits are important considerations, they are separate from, and do not serve as the basis for, the SNG Contract.

Mr. Ulrey identified the following concerns with the SNG Contract:

1. Entering into the SNG Contract at this time fails to consider the dramatically changed gas and coal market conditions and CO₂ cost uncertainties.
2. There is a high probability that the SNG Contract will result in substantial incremental costs to gas customers.
3. The SNG Contract does not act as an effective hedge for gas customers.

4. The SNG Contract does not appear to provide a reasonable balance of risk and reward between IG and the IFA (and therefore the gas customers).
5. The statutorily required guaranteed savings for retail end-use customers is not assured in the SNG Contract.
6. The predominant economic benefit to Indiana, which is the use of Indiana coal, is not required by the SNG Contract and is highly uncertain.

Regarding the dramatic change in gas and coal market conditions, Mr. Ulrey testified (1) there is an industry consensus that there will be low-cost natural gas supplies for some period of time; (2) there is increased volatility of coal and petcoke prices that is expected to continue just as the volatility of gas prices has begun to decrease; and (3) there is great uncertainty about CO₂ risk, any of which create significant uncertainty for customers about the value of the SNG Contract. He cited the Clean Skies Report, compiled by a diverse task force of producers and consumers, which found the growth in shale gas is a fundamental change that reduces the susceptibility of natural gas markets to price instability. He stated the Report specifically encourages regulators and government officials to avoid policies that drive or mandate inelastic demand because it will disrupt the supply-demand balance. It also encouraged regulators to allow long-term supply contracts in the open market.

Mr. Ulrey testified the SNG Contract would limit the utilities' ability to hedge. Utilities already engage in gas hedging through storage fields and the purchase of gas at NYMEX prices one to three years in advance of delivery. Mr. Ulrey also stated Joint Petitioners' projection that 17% of demand will be provided by the SNG Contract is very conservative due to efforts to reduce usage. Vectren North's residential use declined by more than 30% over the past twenty years and is expected to continue due to technology advances, carbon regulation, and energy efficiency. The ability of the SNG Contract to effectively hedge gas price volatility, which is on the decline, with coal and petcoke prices (the price volatilities of which have increased) is suspect. Mr. Ulrey also stated that what might have been a reasonable theory ten years ago does not appear to consider where the markets are today.

Relying on Vectren Energy witness Mr. Norman's analysis, Mr. Ulrey noted additional CO₂ costs have a very large negative impact on the expected outcome of the SNG Contract. For example, Exhibit RN-10 shows an additional reduction of \$252 million in expected net present value benefits over Mr. Norman's Base Case based on gas customers being required to fund the maximum \$0.51 per MMBtu increase in the SNG price if the net CO₂ revenues are negative. In support of Vectren Energy's concern about the high probability for substantial incremental costs to customers, Mr. Ulrey summarized the results of Mr. Norman's analysis. Relying on the Mr. Norman's forecasts, Mr. Ulrey showed that the average residential customer will see a \$34.56 per year increase on average, and the average commercial customer would see a \$144 per year increase. A customer at the SNG Contract usage limit of 50,000 MMBtu would see a \$16,819 per year increase on average. Mr. Ulrey disagreed with Ms. Alvey's calculations of consumer savings and provided prospective information regarding Vectren North's customers in Exhibit JLU-5.

Mr. Ulrey referred to Mr. Norman's analysis in stating that the SNG Contract was not an effective hedge. He also asserted that the potential fuel diversity is not valuable because potential natural gas volatility is replaced by potential coal price volatility, potential additional price risks

related to CO₂ and new taxes, and potential variability of byproduct revenues. Mr. Ulrey acknowledged the capital charge portion of the SNG price provided some elements of a hedge, but on a declining basis over time. He also asserted the SNG Contract does not provide a cap on natural gas costs, nor is it consistent with the recommendations for long-term hedges as advocated in the Clean Skies Report. Mr. Ulrey testified that, as an insurance product, the SNG Contract is a very high premium to only modestly at best hedge the total bill to customers.

Mr. Ulrey said there would be an unreasonable amount of risk assigned to gas customers as a result of the SNG Contract. He supported this by stating the SNG Contract is only a limited hedge, there is a high likelihood of increased cost, and a failure of assurance of the \$100 million in guaranteed savings. Added to these issues are concerns about achievement of incremental revenues (which are shared between the IFA and IG) and the potential costs of New Taxes and Changes in Governmental Requirements costs. Mr. Ulrey also asserted the SNG Contract requires the gas customers to assume 100% of all negative SNG Market Differentials while it shares 50% of positive SNG Market Differentials with IG. Mr. Ulrey described the sources of incremental revenues and stated there is not support for these revenues in the Joint Petitioners' direct testimony. Mr. Ulrey raised concerns about the viability of future CO₂ revenues, given the uncertain status of the Midwest Pipeline. He stated that even if built, the CO₂ could still have a negative cost, which, capped at \$0.51 per MMBtu under the SNG Contract, would total \$252 million (net present value). Mr. Ulrey asserted CO₂ pipeline costs could be passed on to customers without meaningful caps or controls, as well as new taxes on CO₂, which cannot be mitigated through commercial and technically available alternatives. Mr. Ulrey testified the risks transferred to the customers are the kinds that are typically incurred by project equity owners.

Regarding the failure of the SNG Contract to provide guaranteed savings for retail end-use customers, Mr. Ulrey referred to the definition of guarantee in Webster's Dictionary as a pledge or assurance and interprets the statutory requirement for a "guarantee of savings to retail end use customers" as meaning the savings must be realized during the thirty-year term. Mr. Ulrey asserted there could be millions of dollars of additional costs to customers during the term that may not be able to be made up by the remedies under the SNG Contract. Mr. Ulrey testified the SNG Contract does not require the use of Indiana coal, and Ms. Medine's testimony suggests that such use is uncertain. Mr. Ulrey recommended that if Indiana coal is critical to the value proposition of the SNG Contract, it needed to be more certain in the SNG Contract.

Turning to the UMA, Mr. Ulrey questioned the definition of retail end use customer and noted the exclusion of large transport customers from SNG charges and credits, and the allocation of costs among the utilities is not provided for in the SNG Statute. Mr. Ulrey said the reference to statutory debt collection procedures should be removed, utility audit rights should be added, the term should be limited to thirty years, and the provision making IG a third-party beneficiary should be eliminated. With respect to the GCA process, Mr. Ulrey believes any costs related to the implementation of the SNG Contract would be recoverable over a subsequent twelve-month period under the UMA. He noted using a projected twelve-month impact is not precluded by the UMA.

Finally, Mr. Ulrey suggested the SNG Contract should be reviewed in a manner similar to the Commission's current reasonableness review for hedges. Based on current market conditions

and the uncertainties the SNG Contract presents, he concluded the SNG Contract is not in the best interests of gas customers at this time.

E. Angila M. Retherford. Ms. Retherford presented only cross-answering testimony on behalf of Vectren Energy. She is the Director of Environmental Affairs and Corporate Sustainability and Senior Environmental Counsel for Vectren Corporation.

Ms. Retherford described the uncertainties she sees surrounding the issue of carbon regulation, specifically the difficulty in quantifying the potential cost increases resulting from future legislative or regulatory changes. She pointed out that if a carbon tax is imposed on CO₂ emissions from the use of coal, Indiana gas customers would end up paying the tax attributable to the 5.5 million tons of CO₂ expected to be produced by the SNG Facility each year for thirty years.

Ms. Retherford explained the three primary categories of CO₂ risk. First, she described certain legislative risks, including those from (1) the regulation of CO₂ and other greenhouse gases under a cap and trade regime; (2) strict mandatory greenhouse gas performance standards; and (3) a true carbon tax proposal on the fuel source or the emission source. She said even a nominal CO₂ allowance price of \$10 per ton could result in compliance costs of \$50 million per year. Second, Ms. Retherford discussed risks related to regulation of greenhouse gas emissions, including carbon, under the Clean Air Act, and additional uncertainty from the significant volume of litigation currently underway involving such regulation. Third, Ms. Retherford described litigation risks from civil tort suits seeking emission caps and damages, all of which would be passed on to gas customers through the SNG Contract. Additionally, there is uncertainty surrounding whether the Midwest Pipeline will be built because it is contingent on Denbury's ability to find sufficient CO₂ from two to three gasification projects to support pipeline economics.

Further, the SNG Facility will have to comply with Best Available Control Technology ("BACT") requirements in obtaining its air permit, and few, if any, gasification plants have been permitted under the new BACT requirements. It is uncertain how BACT compliance will be determined for the SNG Project. She also stated if the capture and sequestration of CO₂ is required to comply with BACT and the Midwest Pipeline is never built or becomes unavailable/unusable, a suitable replacement option could take years and cost millions. She noted IG's agreement with Denbury has a term of fifteen years, whereas the SNG Contract has a term of thirty years or more.

Ms. Retherford discussed how CO₂ mitigation costs could be passed on to gas customers through certain provisions of the SNG Contract. Ms. Retherford disagreed with OUCC witness Mr. Miller's assessment of the capabilities of the SNG Contract to shield customers from large increases in the price of SNG because the uncertainty surrounding the issue of carbon regulation makes it difficult to account for the risk of cost increases.

Finally, Ms. Retherford stated if approval of the SNG Contract is given, it should be conditioned, at a minimum, by requiring that IG (1) agree, regardless of whether Denbury completes the Midwest Pipeline, CO₂ is capable of mitigation through commercially reasonable

and technically available alternatives, thus making the CO₂ costs fall within the SNG Contract's definition of costs capped under the Change in Governmental Regulations, and (2) agree all potential CO₂ costs, including any type of taxes related to CO₂, will be capped either by the \$0.51/MMBtu cap or the 13.5% cap, depending on the applicable provision.

7. The Six LDCs' Direct and Cross-Answering Testimony.

A. S. Mark Kerney. S. Mark Kerney, Vice President and Chief Financial Officer of Ohio Valley Gas, provided direct testimony on behalf of the Six LDCs in this proceeding. He testified that neither the SNG Contract nor the UMA should be approved by the Commission. Specifically, he said the SNG Contract is a terrible deal with no real guarantee of savings and significant risk of additional costs for the vast majority of customers, as well as businesses. Also, because of the administrative burden of compliance, the UMA should not be approved. Mr. Kerney raised concerns regarding entering into the SNG Contract at a time when the EIA projects low natural gas prices for at least the next fifteen years. He agreed that energy prices are volatile but stated Indiana utilities buy very little gas at spot prices. Instead, they use multiple hedging techniques to mitigate volatility and do so without incurring the additional costs that would be imposed by the SNG Contract.

Mr. Kerney stated that according to Ms. Alvey, a customer using 100 Dth annually would save \$3 per year. He testified that, even if this level of savings were to happen, it would be eroded by costs of the UMA. Additionally, the Six LDCs' average customer that would be subject to SNG Contract uses a lower amount per year, only averaging 75 Dth, which would further reduce Ms. Alvey's projected savings.

Regarding guaranteed savings, Mr. Kerney testified the SNG Contract does not provide for the savings guarantee mandated by the SNG Statute. He further stated the SNG Contract's savings guarantee does not come into play until after the thirty-year term, and even then, the terms of the SNG Contract do not constitute a guarantee of savings for customers as required by the SNG Statute. He testified customers not only have no guarantee of ever realizing the supposed \$100 million in savings, but they are actually at risk of greater losses—losses that are not capped by the SNG Contract. Even if the \$150 million CPR actually offsets customers' losses for the first five to six years as projected by Ms. Alvey, he said her same projections also show that customers will still incur several years of unmitigated losses. He went on to note that more realistic projections of natural gas and coal price growth rates, as described by Mr. Stenger, would result in a more rapid depletion of the CPR and many more years of unmitigated losses to customers.

Mr. Kerney raised concerns about the contract to sell CO₂ and its reliance on construction of the Midwest Pipeline being built. Without the anticipated pipeline necessary to ship CO₂ to Louisiana oilfields, the SNG Project would not be granted federal loan guarantees due to emissions concerns and therefore would not be built. He also stated IG might profit even when customers might not. He referenced a flowchart diagram in RWK-1, Figure 3-1, named Distribution of Benefits and stated the diagram depicts that Leucadia may benefit from the SNG Project when the gas customers realize no financial benefit.

Mr. Kerney's concerns with the UMA included having the IFA and not the Commission be the overseer of the UMA's administrative provisions, the exclusion of industrial transport customers using 50,000 Dth or more (as well as the provision that once exempt, always exempt), the timing of the monthly Price Adjustment or "Customer Charge" invoiced to the utility by the IFA, related bad debt expense, seasonal billing, issues regarding setting up a separate line item on customers' bills and the burdensome, one-sided audit rights of the IFA.

Mr. Kerney said given the statutory requirement that the SNG Contract include a guarantee of savings, he would have expected the OUCC's only witness to address whether the SNG Contract contained such a savings guarantee. Although Mr. Kerney concurred with Mr. Miller that the SNG Contract provided for diversification of the supply of natural gas for Indiana customers, he remained concerned about the risk of customers being exposed to more costs.

Mr. Kerney testified that Mr. Miller's important concerns were his as well. He noted the IFA issued its RFP two days after Governor Daniels signed Public Law 2-2009 and allowed only two weeks for responses to its RFP for a \$2.6 billion project requiring complex technology. He said IG has the incentive to maximize byproduct sales not because of guarantee of savings as suggested by Mr. Miller, but rather through the sharing provisions. Fuel costs represent a majority of the operating costs. He noted that according to Mr. Miller, there is no cap on the actual delivered cost of fuel. He expressed concern about the adequacy of the SNG Contract's protection of gas customers from large increases in the price of SNG due to increases in coal costs, pointing to Mr. Stenger's testimony as supporting evidence.

Mr. Kerney noted several distinctions between the SNG Contract and insurance policies. He stated it is not apparent the Six LDCs' customers would actually want to pay for the insurance. Additionally, insurance policies are competitively priced and if the competitively priced premium is too great a cost, he would choose not to purchase it. As insurance costs change, customers can shop around to find the best deal at the time. Lastly, he stated Leucadia is not committing to a fixed price, but rather a fixed formula designed to ensure cost-recovery for Leucadia regardless of the market value of its product.

B. Morton Marcus. Morton J. Marcus, a consulting economist, provided direct testimony on behalf of the Six LDCs. He addressed certain economic concerns related to the SNG Project that affect the welfare of Indiana households and businesses. He testified that with the alleged \$100 million guaranteed savings, and the 1,558,000 current Indiana households, the savings per household equates to \$64.18, which is \$2.14 per year or 18¢ per month.⁴

Mr. Marcus testified that because the supposed guarantee is unfunded and optional, it does not constitute a guarantee. After the depletion of the \$150 million CPR, there is no cap on losses in the SNG Contract. He raised concerns about variability in consumer bills from one month to the next. He stated the current proposal by Leucadia and the IFA only compounds

⁴ Mr. Marcus testified this estimate does not account for the customers of exempted municipal households. If those households were subtracted, the payout would be somewhat higher. At the same time, this statement does not account for commercial gas customers, who, if included, would reduce the \$64.18 savings per household. He concluded the latter is most probably the greater effect.

variability by introducing a new element: the SNG Contract gas purchase price and sale or market price differential.

He testified IG would receive nearly \$4 billion in capital charges from the IFA over the thirty-year term. Subtracting the \$2.63 billion cost of the SNG Project would leave \$1.36 billion in profits, an amount he deemed excessive, given that more than half of the funding for the SNG Project will come from bonds guaranteed by the federal government.

Mr. Marcus raised concerns about gas price forecasting in general, especially as one goes further in time. He calculated the IFA's Base Case savings of over \$500 million means savings of \$9.52 per year per household. He testified that only after 2032 does Leucadia project that the market price will exceed the SNG Contract price resulting in savings for customers. He noted that because of this, companies might refrain from locating in Indiana or switch to another fuel, thereby decreasing demand and placing a greater burden on the remaining customers.

In his cross-answering testimony, Mr. Marcus addressed the testimony of Mr. Miller and disagreed that the proposed SNG Contract represents a reasonable implementation of the objectives and requirements in the SNG Statute.

C. John T. Stenger. John T. Stenger, the Consultant in charge of field operations for Sycamore Gas Company, provided direct testimony for the Six LDCs. He discussed Joint Petitioners' forecast of future prices for SNG, natural gas and coal; the SNG Facility's production costs; the Joint Petitioners' reliance on byproduct sales for predicting future savings; and the anticipated viability of shale gas and its impact on natural gas markets.

Mr. Stenger agreed with Joint Petitioners that energy prices are volatile, and that the further out the prediction, the less reliable it is. However, he asserted Joint Petitioners have ignored the historic relationship between the price of natural gas and the price of coal. He provided historic information on an MMBtu equivalent basis regarding the prices of crude oil, coal and natural gas from 2003 until the present. From 2005–2011, the price of oil rose 104%, the price of natural gas decreased 32%, and the price of coal increased 21%. He compared this to the forecast put forth by the IFA, which predicts increases of 4.1% for crude oil, 5% for natural gas and only 1.7% for coal. Since the price under the SNG Contract is largely dependent on the price of coal, he said having a low coal forecast could overestimate the benefits and underestimate the risks shifted to the ultimate customers. There was considerable volatility in commodity pricing in 2008. He further noted in the period from July 2007 to July 2008, the price of crude oil rose 93%, natural gas rose 89%, and the price of coal rose 190%. Therefore, Mr. Stenger concluded that because coal prices could be more volatile than natural gas prices, this possibility could negate the stated benefits of the SNG Project.

Using a 4% growth rate for all three commodities starting with their respective January 2011 prices would have a large negative impact on the resulting calculation of consumer savings, making it unlikely that the guaranteed \$100 million would be realized. Mr. Stenger provided other scenarios in which he substituted different gas price forecasts than those used by the Joint Petitioners. He used in Exhibit JTS-5 the forecast from the EIA's AEO 2011 Reference Case, extrapolated beyond 2035. This exhibit shows cumulative costs to customers of approximately

\$1.5 billion. Mr. Stenger testified the EIA's projections merit consideration.

Mr. Stenger provided Exhibit JTS-6, which examines what the natural gas price percentage increase would need to be in order for the SNG Project to have no cumulative losses. He concluded that such a percentage increase was unlikely. In Exhibit JTS-7, Mr. Stenger analyzed the EIA's projections for natural gas as used in Exhibit JTS-5, and inserted a 4% coal price annual increase in the Leucadia model. This yielded another highly negative consumer savings outcome. In Exhibit JTS-9, Mr. Stenger calculated the requisite natural gas price percentage increase in order for the SNG Project to have no cumulative losses in the scenario of a 4% coal price increase. Mr. Stenger again concluded that growth rate would not be realistic. Mr. Stenger testified that natural gas prices would have to grow at a fairly substantial rate from his January 2011 starting point to reach the Base Case starting point. He further stated this growth rate casts serious doubt as to the reliability of Leucadia's savings assumptions. While energy forecasting is far from an exact science, given the highly questionable assumptions on which the claims of savings are based, the risk of losses is very real and serves as the basis for the Six LDCs opposition to the SNG Contract.

Finally, Mr. Stenger expressed concern about the SNG Project's CO₂ revenues. He noted the recent defeat of eminent domain legislation in Indiana, the gubernatorial veto of the SNG projects in Illinois, and the resulting effect on actualizing the Midwest Pipeline. Mr. Stenger challenged the testimony of Mr. Berman regarding shale gas by providing Exhibit JTS-3, a report from BENTEK Energy LLC, an energy market analytics company, which discussed the rapid rise of shale gas supply.

8. NIPSCO's Direct and Cross-Answering Testimony.

A. Frank A. Shambo. Mr. Shambo presented direct and cross-answering testimony on behalf of the NIPSCO. He is Vice President of Regulatory and Legislative Affairs. Mr. Shambo stated the SNG Contract is fundamentally different from current gas supply agreements. He stated NIPSCO is not offering an overall opinion on the SNG Contract, and the price effectiveness of the SNG Contract relative to the market is difficult to measure as contrasted to its hedging characteristics.

Mr. Shambo stated NIPSCO has concerns about the provisions in the UMA for recovery of incremental costs. The UMA is not fully clear regarding the specific mechanics for recovery of such costs by utilities. Mr. Shambo suggested the mechanics for recovery of utility-incurred incremental costs be determined in a Commission-noticed technical conference. This would allow all LDCs, including NIPSCO, to be assured that the allocation methodology, the definition of incremental costs, the formula for inclusion of such costs in quarterly GCAs, and the definition of exempt customers are fair and balanced. He said a key tenet of rate development is the concept of matching costs and revenues to the customer class responsible for those costs and revenues. Therefore, Mr. Shambo concluded it is important to match the allocation process to the collection process for SNG costs. Another concern of his is that intergenerational equity should be enforced in the allocation of costs throughout the thirty-year term.

Mr. Shambo noted Mr. Ulrey's concern about the definition of retail end use customer in

the SNG Statute, but said that after reviewing all of the legislation over the past several years leading up to this proceeding, it is his opinion that the IFA has properly interpreted the legislative intent to exempt larger industrial transportation customers who purchase and arrange for natural gas supply independently from the impact of the SNG Contract.

Mr. Shambo disagreed with Mr. Kerney's assertion that the IFA's decision to exclude industrial transportation customers using 50,000 Dth or more annually from SNG costs in the UMA is arbitrary and outside either the IFA's or the Commission's authority. The IFA realized the group of customers that would be excluded is sophisticated in the energy procurement process and accustomed to risks inherent in its independent gas supply purchases. He further stated NIPSCO's industrial transportation customers have demonstrated a willingness to purchase their gas supplies and enter into hedging arrangements without the help for, or reliance on, NIPSCO for many years. He said there are many examples of the Commission or other state agencies using due process to provide more specific detail to implement an enabling statute, and the establishment of a definition of customer groups to be eligible for, or exempt from, the effects of the SNG Contract fits that role.

With respect to Mr. Kerney's concern that once a retail end use customer is deemed exempt it would remain exempt for term of the SNG Contract, Mr. Shambo disagreed that the UMA is flawed. The IFA is attempting to accomplish two important considerations in keeping the number of exempt customers constant when the UMA is placed into effect. The first of which is to minimize the burden on LDCs rather than increase the administrative burden. Second, a volumetric benchmark that is in play annually could provide an incentive for a customer to use more or less than 50,000 Dth annually simply to avoid an SNG cost or achieve a credit. Mr. Shambo gave other examples of risk of "gaming" the SNG Contract if the opportunity to do so is not resolved as it has been by the IFA.

9. Citizens Groups' Direct and Cross-Answering Testimony.

A. **John Blair.** Mr. Blair stated he serves as the volunteer President of Valley Watch, Inc. ("Valley Watch"), an Indiana not-for-profit corporation whose purpose is to protect the public health and environment of the lower Ohio River Valley.

He testified Valley Watch has provided technical and tactical assistance to groups and individuals who have sought its help on issues they perceived as being threatening to their health and welfare. Valley Watch intervenes in legal and non-legal proceedings to offer an environmental health perspective. Mr. Blair further testified Valley Watch became involved in this proceeding to protect the public health and economy. He criticized the SNG Project's business model and stated it will ultimately be financially irresponsible and result in significantly higher prices paid by Hoosier consumers for gas derived from coal as compared to the more conventional natural gas. He further likened the SNG Statute as being akin to a state-controlled, Chinese Communist Business Model in which it is not unusual for the authoritarian state to dictate who will produce products, who will buy those products and the price. He also questioned whether the SNG Project is a "clean coal" project claiming that clean coal is an oxymoron.

He criticized what he characterized as the parasitic capture and compression of CO₂ for

transport for EOR and asserted that this proceeding must address the issue of climate change. Mr. Blair also stated the SNG Project cannot compete against natural gas over the term of the SNG Contract because of the advent of fracking to produce shale gas. He likened the developers of the SNG Project to the proverbial snake oil salesmen of biblical times. He testified that he is offended that politicians who otherwise say the government should be limited, and programs designed to help the developmentally disabled and the hungry can be cut, while many of those same people are being forced to pay a premium to heat their home just to enrich friends of the Governor. He recommended that the Commission protect the free market, the public economy, and the public health by not approving the SNG Contract.

B. Stephen Obermeier. Mr. Obermeier testified he is on the Steering Committee of the Spencer County Citizens for Quality of Life (“SCCQL”). He testified SCCQL was formed two years ago in response to the SNG Project, and its mission is to fight against having the SNG Facility constructed in the Spencer County region because of the existing pollution levels in that region. SCCQL collected 1,000 signatures on a petition in opposition to the SNG Project, and the response to the petition convinces Mr. Obermeier that there is much opposition to the SNG Project. He said SCCQL opposes it for environmental and economic reasons because Spencer County already has very high levels of industrial pollution from a huge merchant coal power plant and other polluters. As an earthquake specialist, he is concerned about the future levels of earthquake shaking in the region, and such an earthquake could cause the release of harmful gases from the SNG Facility and harmful release of CO₂.

Mr. Obermeier asserted the SNG Project will emit enormous amounts of pollution that would not otherwise exist, and just because it may represent improvements over older coal plants does not make it clean. With respect to the Resolution passed by the City of Rockport in support of the SNG Project, he stated public sentiment that evening was clearly in opposition. He challenged the bases of the facts stated in the Resolution. He testified that about one-third of the Spencer County citizens are against the SNG Project, one-third are supportive, and one-third are uncommitted.

C. Kerwin Olson. Mr. Olson is the CAC’s Program Director. The purpose of his direct testimony is to introduce the testimony of CAC’s expert witness Robert McCullough and explain why, from Mr. Olson’s and the CAC’s perspective, the Commission should not approve the SNG Contract. He stated if the Commission approves the SNG Contract, it will not be able to carry out its mission as an advocate of the public or the utilities, and to balance their respective interests to ensure that utilities provide adequate and reliable service at reasonable rates. He also described his understanding of the legislative history that led up to this proceeding.

Generally, Mr. Olson disagreed with Mr. Miller’s assertion that the SNG Project serves to diversify Indiana’s energy supply. He stated he does not see how making SNG from coal in a state that is almost exclusively reliant on coal for its electricity is diversification. He also disagreed with Mr. Miller’s conclusion that the SNG Contract fulfills the guaranteed savings requirement of the SNG Statute, referring to the testimony of Mr. McCullough for support. He also offered his opinion of the legal effect of the SNG Statute and other statutes relative to the Commission and this proceeding.

D. Robert McCullough. Mr. McCullough is the Managing Partner of McCullough Research. He stated most of the natural gas customers of utilities in Indiana have been offered a derivative that has little or nothing to do with the underlying commodities. He said the SNG Contract is not an attractive derivative or good hedge against high natural gas prices because its price is not fixed, among other reasons.

Mr. McCullough described the economic components of the SNG Contract. He contended that one critical part of the SNG Contract is not described in the testimony of either Ms. Alvey or Mr. Maley, namely the provision that debt service requirements come ahead of Incremental Revenue sharing (Section 5.4(b) Limitations on Adjustments). Any cost overruns would be financed by a combination of debt and equity. Mr. McCullough testified this is important because Duke Energy Indiana, Inc. experienced cost overruns with a very similar technology. He stated it is very unlikely the overruns would be financed 100% by equity as currently modeled in the IG and IFA models and commented generally that risks were not adequately addressed by the models.

With respect to how to model the SNG Contract, Mr. McCullough characterized the SNG Contract as embodying an exotic derivative. He said he uses this term to describe derivatives that do not have standard analytic tools because of their complexity or uniqueness, and stated that the appropriate tool for analyzing such an exotic derivative would be a Monte Carlo analysis, which he called a standard approach in mathematical finance. He provided illustrations, using a roulette example, of what a Monte Carlo analysis means. Mr. McCullough testified he started out with the basic IG model, only making changes to certain assumptions and changing the hard wiring related to using equity only for cost overruns. He applied a discount rate of just over 6% to his calculations, based on a recent weighted cost of capital number approved by the Commission. He then went on to apply what he characterizes as a Monte Carlo analysis to the SNG Contract by using an analytical tool called Crystal Ball, which can be used with Excel, the format used by the underlying model.

Mr. McCullough described the first step in his analysis as identifying the source for his data. He chose the 2011 EIA early bird forecast and noted IG's and the IFA's criticism regarding EIA forecasting. While acknowledging that everyone does not do an adequate job with such forecasts, he maintained the EIA forecast was the best choice, as opposed to forecast shopping.

In his second step, Mr. McCullough calculated the distribution of actual prices over the last decade. He then used this distribution to model natural gas prices around the EIA forecast. He charted his distribution of prices and used sample year 2020, which appears to be a bell-shaped curve. The Crystal Ball program selects a value from the distribution. The median number in any year was chosen more often, and the values in the tail were chosen less often because they had lower probability. To extend the EIA forecast past 2035, Mr. McCullough derived the statistical line of best fit for 2016–2035 and extended it out for the following decade. He used a similar methodology with EIA data to model oil, coal, and electricity prices. Since experience in recent years is to see these prices vary independently, he stated he allowed the Monte Carlo model to pick adjustment factors independently for each commodity. Leucadia's sudden jump in oil price escalation in 2035 was somewhat mysterious to Mr. McCullough.

His methodology for modeling argon, rare gases, and sulfuric acid used historical price information from the Bureau of Labor Statistics for SIC 2813 and SIC 28193. He found the standard distribution of the real price from the BLS data and used it to form the distribution for the Monte Carlo.

He added one variable to his Monte Carlo analysis, which is cost overrun. He stated the problem is that Leucadia has decided to act as its own contractor and has subcontracted the actual construction to Turner Industries, a firm without extensive experience in this technology. Mr. McCullough assumed a median cost overrun of 45%, based on the Duke Edwardsport experience. He stated the amount of cost overrun does not directly drive the SNG Contract price. However, as the SNG Project's capital costs increase, the first claim on supplemental revenues for debt service may reduce the availability of supplemental revenues to reduce consumers' cost. The defeat of eminent domain legislation in Indiana and the Illinois Governor's veto of gasification plant bills will most likely have an impact in Denbury's plans to build the Midwest Pipeline and will therefore create the possibility of cost overruns from IG developing other CO₂ alternatives.

Mr. McCullough concluded from his Monte Carlo analysis, with the assumptions described above, that the expected cost to consumers is \$458 million over the life of the SNG Contract. He displayed the distribution of his results in a chart on page 32 of his prefiled direct testimony. The results show that in 57% of all cases the consumer would lose money. Based on this conclusion, Mr. McCullough recommended that the Commission reject the SNG Contract.

With respect to IG's alleged guarantee of savings for customers, he noted the IFA's option to foreclose on the SNG Facility was not a meaningful guarantee for Indiana's captive gas customers because the value of the SNG Facility thirty years from now is doubtful and certainly not guaranteed. Mr. McCullough agreed with Mr. Miller's concern that the SNG Contract is not procured in a competitive environment. He stated if the state wishes to assure that gas consumers are hedged against a rise in gas prices, the best answer is to hold an all source bid for a hedge.

10. Lincolnland's Direct Testimony.

A. Thomas F. Utter. Mr. Utter, Executive Director of Lincolnland, testified Lincolnland supports the SNG Project because it will provide a tremendous economic boost to Spencer County. He stated construction of the SNG Facility will require extension and reactivation of several miles of rail line that, together with the SNG Facility's river terminal, will present value added assets to Indiana and Spencer County. Mr. Utter testified Lincolnland also considered the environmental impact of the SNG Project. He attended one meeting with state and federal officials to assure that the SNG Project would be held subject to (by name) air, water, land, mussel, brown bat, archeological, noise, and other environmental standards.

B. Ferman M. Yearby III. Mr. Yearby, a teacher for South Spencer High School and the President of the Rockport City Council, testified the Rockport City Council supports the SNG Project and believes it will be a life-changing watershed for the economic history of not just Rockport and Spencer County, but for all of southwestern Indiana. It will enable the use of the area's coal to take care of energy needs and in the process provide countless

jobs. He also testified he considered the environmental impact of the SNG Project on Spencer County. He spoke with Senator Richard Young and Representative Russ Stilwell, who assured him it was environmentally safe. Mr. Yearby further testified the City of Rockport has appropriated funds to help Lincolnland obtain property rights for the construction of the SNG Facility and adopted resolutions in support of the SNG Project. Finally, he testified he believes the SNG Project has general support from most citizens of Rockport and Spencer County.

11. Industrial Group's Cross-Answering Testimony.

A. **Martin J. Marz.** Martin J. Marz, an Energy Advisor and Senior Consultant with J. Pollock Inc., offered his cross-answering testimony on behalf of the Industrial Group. He focused on the difference between natural gas transportation customers and retail end use customers, whether the SNG Contract provides an effective hedge for transportation customers, and whether transportation customers are or should be included as retail end use customers for purposes of the SNG Contract.

Mr. Marz explained service taken by transportation customers differs substantially from service taken by retail end use customers. Transportation customers are customers who take responsibility for all aspects of obtaining their own gas supply, including responsibility for arranging for transportation, scheduling and nominating deliveries and managing imbalances, as opposed to the bundled purchase of retail gas service by retail end use customers. He asserted the proposed SNG Contract and the UMA do not provide an effective hedge for transportation customers who are taking service under service tariffs. Because of these differences, Mr. Marz argued it is not discriminatory to exclude transportation customers from the definition of retail end use customers under the SNG Contract.

Mr. Marz stated the alleged hedging benefits attributed to the SNG Project are unnecessary for transportation customers. He observed transportation customers now have the opportunity to hedge their gas supply costs, but retail end use customers as defined by the UMA are too small to effectively hedge on their own. Mr. Marz further argued that the SNG Contract does not constitute a price hedge to the extent the SNG price will fluctuate based on the price of coal and O&M adjusted for inflation.

Finally, Mr. Marz testified transportation customers do not fit the statutory description of a retail end use customer found in Section 10 of the SNG Statute. He said transportation customers do not acquire energy at retail for their own use from a gas utility that must apply to the Commission under Indiana Code § 8-1-2-42 or under a program through which the customer purchases gas that would be subject to price adjustments under that Section if the gas were sold by a gas utility. He explained transportation customers purchase gas that is sold at a market price in the wholesale deregulated natural gas market. Further, he said transportation customers are not restricted to a supplier list created and maintained by a local distribution company.

12. Joint Petitioners' Rebuttal Testimony.

A. **Jennifer M. Alvey.** Ms. Alvey explained market risk and volatility in the natural gas market were considered, and mitigation of these risks was among the primary goals

of the SNG Contract. Ms. Alvey also noted the economic development aspects of the SNG Contract were not the primary reason for the Authority to enter into the SNG Contract. The primary purpose of the SNG Contract was to fulfill the General Assembly's charge that the Authority enter into this transaction to provide diversification of the supply portfolio and mitigate risk to retail end-use customers.

Ms. Alvey disagreed with Vectren Energy witness Mr. Ulrey's statement that the SNG Contract is irrevocable by pointing out the provisions of the SNG Contract which allow the Authority to terminate it. While customers may experience a charge at certain points during the term of the SNG Contract, Ms. Alvey explained the \$150 million CPR must be exhausted before any customers are charged. Moreover, Ms. Alvey asserted cost overruns associated with construction and operations are borne exclusively by IG. She also said Mr. Ulrey's statement does not consider the cap on CO₂-related costs, which are borne by IG as well. Additionally, any cost overruns, or costs incurred due to delays, relating to the construction of the SNG Facility are the responsibility of IG and its equity holders.

Ms. Alvey stated the transaction represents the diversification of the natural gas portfolio for retail end use customers, which is more akin to an insurance policy. She stated Mr. Olson ignores the fact that gas customers are 100% exposed to natural gas commodity price risk today. Gas consumers are currently exposed to a substantial natural gas commodity price bet with very little protection. According to Ms. Alvey, the SNG Contract will diversify consumer supply so a portion of the supply is paid for under a cost-based contract, which will reduce overall price risk for consumers.

Ms. Alvey also stated the SNG Contract, the UMA, and the SNG Statute provide the parameters for the Authority's purchase and sale of the SNG and the pass-through of credits and debits to customers. While it is correct to say that the Commission is not charged with administering the SNG Contract, the Authority is also a state regulatory authority and is charged by the SNG Statute with administering the SNG Contract. She said certain related charges by the regulated utilities will continue to be regulated by the Commission. Ms. Alvey pointed out the SNG Statute does not eliminate the Commission or its regulatory responsibilities. According to Ms. Alvey, the SNG Contract, as administered by the Authority, protects the ratepayers by assuring IG will have to share any benefits obtained under the SNG Contract with them.

Ms. Alvey noted the importance of the Authority's right to terminate the SNG Contract if the SNG Facility is not capable of supplying SNG. She stated the Authority's right to terminate in the event that commercial production has not begun protects consumers from this risk. Ms. Alvey explained the only negative net incremental revenues to flow through to the SNG Price are from CO₂ and those are capped at \$0.51 per MMBtu. Any other net negative incremental revenues are absorbed by IG.

Ms. Alvey discussed the requirements set forth in the SNG Statute. She noted the SNG Statute imposes a requirement for Commission approval of the SNG Contract, which she contended is different from the standards typically applicable to public utility matters. Ms. Alvey stated that while the Commission must approve the SNG Contract between the Authority and IG, it does not appear necessary that the Commission make a public interest finding. She noted the

Commission needs to make a finding that the SNG Project's electric generation is in the public interest in order for it to be eligible for certain tax credits.

Ms. Alvey stated the process by which the SNG Contract was entered into between the Authority and IG was open, fair, and public. She stated the Authority was not required by law to go through the RFP process, but chose to do so for purposes of transparency and to allow for competition. She stated the Authority had no control over how many parties, or what types of parties, would respond to the RFP. Even though only IG responded to the RFP, Ms. Alvey said the Authority's research and consultation with the OUCC and Shaw assured the SNG Contract was reasonable. Ms. Alvey testified the SNG Statute directed the Authority to attempt to negotiate an agreement that accomplished the underlying policy goals and met the statutory requirements. She stated if the SNG Statute had directed the Authority to pursue a different type of bid, the Authority would have done so.

Ms. Alvey explained the capital component of the SNG price was based on IG's actual capital cost. She said the Authority reviewed these calculations and determined the costs were not excessive. The Authority also engaged Shaw to conduct a due diligence review of the SNG Project, which concluded the capital component of the SNG price is not excessive. Ms. Alvey stated penalties for Btu levels and purity will be borne solely by IG, not retail end use customers. The heat map is one of the tools used to quantify risk and only considered the gas and fuel components because these two factors had the most impact on the SNG price. She explained the heat map starts from the Base Case savings forecast on an average annual basis, as provided in the Authority model and Consumer Bill, and moves a reasonable distance one way or the other from that point.

Ms. Alvey explained the SNG Contract should make natural gas a more competitive option because when gas prices are high, SNG will provide a credit to customers, reducing their energy bills and mitigating price impacts. In virtually any situation, the customers will not bear all of the risk under the SNG Contract as they do with their current utility service. Ms. Alvey explained the SNG Statute requires a guarantee of savings over the thirty-year SNG Contract term. She also explained the sureties provided to ensure the guaranteed savings are realized.

Ms. Alvey responded to the concern that there might be outstanding debt with a senior position in the proceeds from the sale of the SNG Facility if the Authority elects to sell it to fund the savings guarantee shortfall. She explained IG cannot incur additional debt senior to the Authority's interest without the Authority's approval, and the Authority would not approve additional debt that would jeopardize its position. Ms. Alvey testified the Authority and the OUCC are required to act in the best interest of the public. It is clear the Authority, with the advice of the OUCC, was obligated to try to achieve the best result for ratepayers in negotiating the SNG Contract. She stated the CPR provides a significant benefit to retail end-use customers, which, based upon reasonable projections, will last for eight years.

Ms. Alvey testified net incremental revenues are shared between IG and the Authority, regardless of Market Differential. If Market Differential is negative, the Authority does not lose the benefit of its 50% share, and IG keeps its 50% share. The Authority's share will still be used to reduce the price of SNG, and thus the amount of the charge that would otherwise be passed on

to customers. Ms. Alvey testified the SNG Contract, through the \$0.51 per MMBtu cap and the 13.5% limit on charges due to Changes in Governmental Regulations, reduces the risk of future CO₂ regulation borne by customers and transfers it to IG. She noted IG has a planned solution for future CO₂ regulation; CO₂ will be used for domestic oil production and generating revenue. She stated these are options not readily available to existing Indiana utilities. Ms. Alvey also responded to concern that costs resulting from Changes in Governmental Regulation are potentially capped at 13.5% by clarifying that these charges are actually, not potentially, capped at 13.5%.

Ms. Alvey indicated the Authority is agreeable to a technical conference to resolve administrative issues relating to the UMA as long as Mr. Maley's concerns and issues with the technical conference are properly addressed. Ms. Alvey noted IG prefers to use Indiana coal and expects it to be the most cost-effective source of fuel for SNG production. However, no requirement that Indiana coal be used is included because it would not necessarily allow for production of SNG at the lowest possible cost.

Ms. Alvey stated the General Assembly, in passing the SNG Statute, determined the Authority is the appropriate entity to administer the SNG Contract. The Authority had not before administered a gas contract, but it engaged Shaw to provide technical support as it evaluated the SNG Contract. She stated the Authority has a strong history and robust experience with complex financial transactions, and since the SNG Contract represents the financial diversification of a portfolio, the Authority's experience in that area is significant. Further, the Authority's lack of prior experience with gas issues and transactions was the reason the Authority was directed to consult with the OUCC. Ms. Alvey explained that, in its advisory role, the OUCC provided advice to the Authority during the negotiation process and was able to help the Authority craft the best arrangement for retail end-use customers.

Ms. Alvey testified that the individuals IG has retained for the SNG Facility's operations have significant experience managing the Coffeyville, Kansas gasification plant. Shaw also verified that the IG staff is competent and sufficiently experienced for the SNG Project. Ms. Alvey argued that delays in this matter could have unfavorable consequences. The largest negative impact would be the likely failure to obtain the federal loan guarantee. She stated delaying the SNG Project would mean it would likely not be undertaken because construction costs and interest rates would be likely to increase. Ms. Alvey disagreed with Mr. Kerney's contention that the Commission should determine which customers participate in the SNG transaction; this issue is initially dealt with by the SNG Statute and clarified by the SNG Contract.

B. Kevin S. Reilly. Mr. Reilly is a Senior Manager for American Appraisal Associates, Inc., where he provides direction and technical support concerning special-purpose and multiproperty/multidiscipline valuations. He rebutted testimony presented by parties that the guarantee of consumer savings in the SNG Contract, which is secured by the future value of the SNG Facility, is not adequate by showing the value through his appraisal. Based on his analysis, the value of the SNG Facility as of June 30, 2046 will be \$4,545,000,000 in nominal dollars, or \$1,778,000,000 in 2008 dollars.

Mr. Reilly explained his firm focuses on complex industrial properties such as the subject property, specifically in the energy sector. American Appraisal's opinion is based on perceptions of the current market reflecting economic conditions as they existed on the date of its report. He expected the SNG Facility will be completed in 2016, and it will be maintained as necessary to keep the assets in a safe and reliable operating condition, which allows for normal wear and tear, and that the property would be managed competently.

Mr. Reilly testified the land value was based on the option sales pricing of the land, provided by IG management. The option is the land's transaction price the land once the regulatory process is concluded and the SNG Project commences. The investigation and methodology employed by American Appraisal for the valuation dealt with all the coal gasification assets necessary for the SNG Project's continued operation as a business. Transmission/pipeline assets not owned by IG and personal property of the employees are excluded from the valuation. In order to provide meaningful value conclusions, commonly accepted appraisal procedures and techniques were followed, and Mr. Reilly also noted data for the property was analyzed using information from public sources and data provided by IG. This information has been accepted as factual and accurate and was reviewed only for reasonableness.

All three of the traditional approaches—value sales comparison, income, and costs—were considered, but Mr. Reilly explained the sales comparison approach was not used in the appraisal because this appraisal is determining the future value of the property, there are no current or anticipated future transactions, and the coal gasification market is ever changing. The coal gasification market, according to Mr. Reilly, is a new and complex market in which supply, demand, and commodity prices are always changing.

The income approach measures the value as the present worth of monetary benefits anticipated to be derived in the future from ownership of the asset. Mr. Reilly stated these monetary benefits are based on the income stream expected to be available to the asset owner or to a typical market participant. The present worth of the future monetary benefits is measured by taking into account the duration and pattern of the projected income stream and the risk inherent in realizing that income stream. The risk element is recognized by discounting the projected income stream at a rate commensurate with the risk perceived by a prospective investor or market participant in the subject compared with other investment opportunities. The discount rate is the result of a prospective investor's evaluation of the relative risk of the investment under review.

The discounted cash flow ("DCF") method of the income approach was used to conclude a value through the measure of the direct economic benefits derived from ownership in the form of cash inflows and outflows attributed to the SNG Project, stated at their present value. Mr. Reilly stated that for the SNG Project, cash inflows are derived from income resulting from the sale of SNG, market power, CO₂, argon, sulfuric acid and rare gases. Cash outflows arise from operating expenses, future capital expenditures and any required influxes of working capital necessary to support growth and sales revenue.

The utilized capacity of the asset is based on a full load average weighed fuel to SNG efficiency of 54.24% and a fuel blend of 15% petcoke and 85% coal. Mr. Reilly stated the annual

SNG production is assumed to be a constant 47.182 million MMBtu as provided in the IG operating projections. He said this assumption was reviewed and deemed to be reasonable for use in the projections for the years 2046 to 2052. In the DCF analysis, management provided market forecasts for each of the underlying revenue sources, which were developed by independent third parties. These were reviewed and tested for reasonableness as part of his analysis.

The primary expense for the SNG Project is coal. In the DCF analysis, the management coal forecast for 2016 to 2045, which was based on EIA forecasts, was utilized. Mr. Reilly further stated that to develop the total annual costs for 2046 to 2052, he used the final year's price of the management forecast for coal (2045) and continued to grow it at an inflation rate of 2.5% annually. The concluded prices were then multiplied by the annual coal usage of 3.2 million tons to yield the total annual cost.

Operating expenses were based on forecasted operating results as provided in management's 2016 to 2045 operating plan. He stated the final year of the management forecast (2045) was used as the basis for the DCF analysis. The forecasted 2045 management operating expenses were grown by an inflation rate of 2.5% to develop annual operating expenses for 2046 to 2052. Based on discussions with management, the SNG transportation cost was held constant throughout the management forecast as well as 2046 to 2052. Given the prospective nature of the valuation date, he computed a WACC as of December 31, 2010 and deemed it to be reasonable for the future valuation date. Mr. Reilly further stated an after-tax discount rate of 8.5% is appropriate. He then converted the after tax discount rate to a pre-tax discount rate of 14.3%.

The cash flows were discounted to present value at the appropriate pre-tax discount rate over a six-year projection period. He also stated for the period beyond this projection period, the projected income, after deductions, was capitalized by a direct capitalization rate and then reduced to present value using the present-value factor at the end of the projection. The indicated value of the SNG Facility as a viable operating entity into the future is equal to the sum of the present values of the interim projections of income after deductions plus capitalization of the projected future profit also discounted to present value. Mr. Reilly stated that as derived with the DCF analysis, the business enterprise value for the SNG Facility is concluded to be \$4,910,496,000.

The cost to construct the SNG Facility was used as the basis for determining the cost of replacement ("COR"). The COR as of June 30, 2046 was calculated by inflating the total cost to build the SNG Facility, which was provided by IG, by the long-term growth rate of 2.5% per year. He testified that after determining the COR, a deduction must be made to reflect any physical deterioration inherent in the property due to age and wear and tear. The physical condition of the property as of June 30, 2046 was estimated based on an age/life relationship and estimates of effective age and remaining useful life. The extent of physical deterioration was expressed as a percentage amount.

Mr. Reilly stated coal gasification technology, in its current form, is a relatively new technology. It is difficult to predict and quantify what functional obsolescence should be applied thirty years in the future. By looking at the past advances and performance indicators in the

chemical process industry, it would not be unreasonable to estimate a functional obsolescence penalty as of June 30, 2046 at 10%. Economic obsolescence (“EO”) is the loss in value resulting from the influences external to the property itself. Mr. Reilly noted the income shortfall method was considered in this analysis, and it was concluded that no significant amount of EO as of June 30, 2046 exists.

Based on a working capital comparison of typical buyers or market participants, it was concluded that the normal working capital for the business was 10% of annual revenues. Mr. Reilly stated this indicates a working capital position of approximately \$128,803,000 based on the forecasted revenues of \$1,288,028,000. Intangible assets consist of the trained and assembled workforce and management team, permits, drawings, and operating procedures. He testified that based on experience in the valuation of intangible assets in chemical process plants, a range of 5%–10% of the business enterprise value is associated with the identified intangible assets. The DCF analysis of the SNG Facility, concluded the business enterprise value as of June 30, 2046 is \$4,910,496,000. For the purpose of this appraisal, the intangible assets are valued at 10% of the business enterprise value, or \$491,050,000.

The cost to option and acquire the land was used. Mr. Reilly stated the 1,341 acres of land associated with the SNG Facility is currently optioned at \$21,856,922, or about \$16,298 per acre. This cost to option and purchase the land was then brought forward to the appraisal date of June 30, 2046 to \$56,553,000 by using a 2.5% annual inflationary rate. All elements of the cost approach—cost of replacing, physical deterioration, functional obsolescence, and economic obsolescence—have been discussed and quantified. Mr. Reilly testified that, as derived by the cost approach, the business enterprise value for the SNG Facility is concluded to be \$4,178,700,000.

For the purpose of his appraisal, a long-term growth rate was projected using historical and projected inflation trends. He stated the annual changes in the Marshall & Swift Chemical Index for the thirty-four year period from 1977 to 2010 were averaged to indicate an annual change of 3.4%. He also analyzed the EIA’s 2010 AEO long-term, twenty-eight year growth projection. One of the 2010 AEO’s macroeconomic indicators utilized is the gross domestic product chain-type price index. The annual changes in this index for the twenty-eight year projection, spanning from 2008 to 2035, were averaged to indicate an annual change of 1.8%. Additionally, Mr. Reilly analyzed data from The World Bank and the U.S. Bureau of Economic Analysis (“BEA”) regarding implicit GDP price deflators. Over the last thirty years, 1980 to 2010, the average of The World Bank and BEA implicit price deflators have been 3.1% and 2.9%, respectively. Considering the preceding analysis, Mr. Reilly concluded the long-term growth rate to be 2.5%.

Certain sensitivity analyses were requested for natural gas pricing and, as a result, two sensitivities were performed. He stated natural gas price forecasts from the EIA 2011 AEO and from EVA were utilized, given the prospective nature of the appraisal and the historical changes observed in the price of natural gas. These forecasts were utilized as the base 2045 price, which was then grown by the concluded inflation rate for 2046 to 2052. Mr. Reilly testified all other assumptions were kept constant. Based on the revised base price for natural gas, the EIA and the EVA sensitivities produced business enterprise values for the property of \$4,731,220,000 and

\$3,555,848,000, respectively.

C. Philip Q. Hanser. Mr. Hanser is a Principal with The Brattle Group and offered testimony to rebut the analyses put forth by Mr. McCullough and Mr. Norman.

Mr. Hanser testified the SNG Project will use coal, the price of which has historically been less volatile than the price of natural gas, to produce SNG. Therefore, there is likely to be greater stability in the long-term price of the natural gas produced by the SNG Project compared to reliance on spot prices or short-term contracts for natural gas for periods significantly shorter than that of the SNG Contract. Coal has historically lent itself to longer-term contracting than natural gas, which also should contribute to a relatively less volatile price for the natural gas produced. He further stated the SNG Contract provides positive value to consumers in a variety of the potential energy scenarios that have been put forth and, thus, demonstrates relative robustness.

Mr. Hanser disagreed with Mr. McCullough's description of the SNG Contract as a financial derivative, which he said uses negative connotations to suggest that since the SNG Contract is a derivative, it must be adverse to consumers. He said it is not a derivative because it is not a tradable security, as defined in Mr. McCullough's testimony. The SNG Contract does not lack transparency in its terms but provides well-defined provisions regarding the responsibilities, including cost and revenue sharing, which each party will assume.

The SNG Contract is cost-based and designed to shield consumers from future volatility and higher natural gas price levels, it is therefore the type of contract consumers would consider, especially in the context of geopolitical events that result in higher price levels and higher price volatility. Mr. Hanser stated a long-term cost-based contract, such as the SNG Contract, provides an assurance that the cost of the product will not exceed its production cost and, thereby, protects the consumer from factors that could dramatically affect the market price of the commodity. He said in some ways, Mr. McCullough's example of world events represents a price and volatility risk that the SNG Contract is designed to insure against.

Mr. Hanser asserted Mr. McCullough used Monte Carlo modeling inappropriately in evaluating the SNG Contract. He said Mr. McCullough made significant technical and conceptual errors in implementing his Monte Carlo analysis, rendering his results and conclusions unreasonable and unreliable. He concluded four of these errors completely invalidate any useful substance that Mr. McCullough's Monte Carlo analysis might have contained.

Mr. Hanser claimed Mr. McCullough appears to have assumed the distributions of future commodity prices are symmetric around an average value. He noted Mr. McCullough's graphs of the distributions of the commodity prices that he simulated are defined in absolute price levels (i.e., dollar per unit of the commodity), and they appear to be perfectly symmetric around a give average (mean). These features represent violations of the standard approach to Monte Carlo simulation of commodity prices, resulting in mischaracterizations of how such prices behave, and an unreasonable analysis. He also noted there are numerous academic and empirical references that describe how absolute price levels of commodities do not follow a pattern of having a symmetric variance around an average value. He noted articles that said gas and coal

are storable, and there are futures contracts traded on both, so a risk-neutralized process for forward prices can be used.

He said based on that observation, the geometric Brownian motion approach is what should be used. It has at its basis the assumption that one cannot simulate price levels with a range of variance around a mean value in each period, but that the appropriate aspect of the price series is the percentage change in the prices. He pointed to references in Mr. McCullough's testimony that specify the appropriate approach to modeling power and energy prices is to model the percentage change in prices from one period to the next, rather than the absolute level in the price.

It is also important to note, according to Mr. Hanser, that the lognormal distribution of commodity prices is not a symmetric distribution—it is skewed to the right. This means that for a given level of risk, the size of any potential decrease is smaller than that of any price increase. This implies the price series is more likely to exhibit a significant upward price excursion. He said commodity prices are generally assumed to follow a lognormal or similarly skewed to the right distribution such as extreme value or what is called the Gumbel distribution. He noted Mr. McCullough's own reference suggests that commodity prices are lognormally distributed.

Mr. Hanser said one of the unreasonable and unreliable practical implications can be seen at page 18 of Mr. McCullough's testimony where he projects the 2020 natural gas price to be \$1.05/MMBtu. He noted this is an economically impossible result for any commodity that can be stored since one could hold on to the commodity until demand has outstripped its supply, and positive prices result.

Mr. Hanser asserted Mr. McCullough seems to have assumed that the energy (commodity) prices in one year are independent of energy prices in the prior and following year, which is incorrect. He said there is no evidence that Mr. McCullough has made certain that the commodity prices follow a reasonable time path. It is incorrect to assume that the prices are not related from one year to the next. There is a substantial body of econometric work that analyzes the correlation over time of commodity prices and, in general, economists think of a commodity as following a trajectory over time or time path, which embodies the correlation of the commodity from one period to the next. Mr. Hanser further testified Mr. McCullough's failure to consider the relationship of commodity prices across time in his Monte Carlo analysis would inevitably result in wildly volatile price swings from one year to the next without any bounds. He concluded this is not a reasonable result, and although natural gas is subject to substantial volatility, the degree to which prices vary from one period to the next is partly determined by the time pattern of those prices, a feature completely ignored in Mr. McCullough's analysis.

Mr. Hanser said the exact methodological and computational steps Mr. McCullough performed to derive the variance around each year's mean prices are unclear. Mr. McCullough stated he calculated the distribution of actual prices over the last decade and then used this distribution to model natural gas prices around the EIA forecast. Mr. Hanser described this description as vague and said that he seems to suggest he used the EIA forecast as the mean value in each year round which he draws normally distributed forecast errors. Overall, Mr. McCullough's modeling of commodity prices is not consistent with the literature that he himself

cites, and his results are highly suspect and based on erroneous and flawed implementation of the approach to modeling commodity prices.

Mr. Hanser said Mr. McCullough assumes no explicit correlation among various commodity prices. Mr. Hanser disagreed with Mr. McCullough's approach to allow the Monte Carlo model to pick adjustment factors independently for each commodity in Leucadia's derivatives market basket. He said this approach fails to recognize that some commodities (e.g., natural gas and electricity) may be positively correlated in such a way that if the price of one is high, in most likelihood the other is simultaneously high. He said this approach to modeling is unreasonable, and Mr. McCullough provided no empirical or qualitative data or references to support his assertion.

Because of these significant mistakes in Mr. McCullough's choice of input assumptions and implementation methodologies, Mr. Hanser believed one cannot rely on his analysis or results to determine savings from the SNG Contract.

With regard to Mr. Norman's testimony, Mr. Hanser testified he relied on two types of models, proforma and stochastic. Mr. Hanser stated Mr. Norman's proforma model, which aims to replicate the results reported by the IG analysis, projects the likely cost of the SNG Contract and compares that cost with the cost of purchasing the same amount of natural gas from the market. The main problem with Mr. Norman's proforma model is, according to Mr. Hanser, that he implemented a number of changes to the assumptions and inputs to the original IG model, which is a misinterpretation of the model or are unnecessary. Specifically, Mr. Hanser stated that Mr. Norman used a significantly lower inflation rate than IG did, discarded the use of petroleum coke in the fuel blend, and made several corrections to the model that have been rebutted by Mr. Maley. Assuming the SNG Project will not use petroleum coke, even when its prices are relatively low, forces the simulated SNG Contract price to be unnecessarily higher than what IG anticipates will materialize.

Mr. Hanser testified concerning the importance of differentiating between the discount rate and inflation, and Mr. Norman did not seem to do this. Mr. Hanser stated that under either of these rationales, the promise of a future payment should be discounted from the future date back to the present, and the return should also be sufficient so as to not be eroded by inflation.

Mr. Hanser disagreed with Mr. Norman's stochastic model for three reasons. First, he said Mr. Norman used a technique known as the Heath-Jarrow-Morton framework. This technique is typically used to value options which have the characteristic that at each period, the holder of the option must decide whether to exercise it. He believed it is inappropriate in the context of the SNG Contract. He explained once the SNG Contract is signed, it precludes the notion of optionality because Indiana's customers pay for the SNG Project's output for thirty years without the ability to reevaluate each year. Second, the value of the SNG Contract should be determined by the expected, or the average, value of the SNG Contract over the length of its term. He explained that expected value depends on the expected price path of natural gas and coal/petcoke inputs. Simulating volatility around such average paths is unnecessary and such a simulation would not provide any additional information to the expected value. He said the only determinant of the SNG Contract value is the assumed average commodity price path over the

thirty years and that value is provided by the fuel price forecast and not by the stochastic simulation. Finally, he said Mr. Norman's descriptions of his findings seem to draw unwarranted conclusions. For instance, Mr. Norman neglected to point out that while his results show, at the 80% lower confidence interval, up to \$2 billion in 2008 dollars in costs, and the upper 80% confidence interval indicates savings could be as high as \$2 billion.

Mr. Hanser said the estimated customer savings of the SNG Contract are highly dependent on the choice of natural gas price forecast. It is not unusual to find a varied range of future price forecasts for natural gas. Mr. Hanser further stated much of future energy commodity prices are driven by factors, the importance of which may not be understood at the time of a particular forecast and unforeseen events. Commodity price forecasting often reflects myopic views of market trends that tend to dominate forecasters' views. This tendency is apparent in most of the public forecast data we reviewed, including the EIA gas price forecasts. Besides suffering myopia, forecasts often suffer what may be described as a kind of memory loss in that forecasts sometimes fail to account for previous failings. Mr. Hanser stated this does not necessarily mean commodity price forecasts are consistently unreliable and wrong. However, as of 2010 or 2011, the best that industry forecasters can do is to project what is known about the future and simulate the future markets under various scenarios and try to predict how prices might behave under different future scenarios. He said some forecasters may get the future right and others may predict wrongly, but no one knows with certainty who will be right or wrong.

The best way to analyze whether the SNG Contract is favorable compared to the market prices of natural gas is to analyze its expected present value to the customers. Mr. Hanser stated the best and the simplest way to perform the expected consumer savings is to compare the expected present value of the cost that consumers will pay under market price and compare that with the expected present value of the cost of the SNG Contract. If the expected value of the market prices is greater, then there is a positive savings to the consumers. If the expected market prices were lower than the SNG Contract prices, the IFA can negotiate to limit the exposure of the consumers such that the consumers do not pay more than the market costs. The IFA has negotiated several mechanisms in the SNG Contract, including the CPR, the concepts of negative and positive Market Differential sharing, and the Guaranteed Savings backed by several end-of-term options, to protect Indiana consumers given the uncertainties associated with future market prices of natural gas.

Although natural gas prices are currently trading in the \$4-\$4.50/MMBtu range, Mr. Hanser indicated it is not reasonable to assume this would continue to be the case in the long-term. It is true that recent developments in the exploration and extraction of shale gas have affected the market prices of natural gas and reduced them relative to the market prices during the period between 2007 and 2008. As pointed out by Mr. Berman, the long-run cost of extracting shale gas is close to the \$7/mcf range. Mr. Hanser stated at that price, it would be reasonable to assume that the \$4-\$4.50/MMBtu price range would not provide sufficient return on gas exploration investments and therefore will not be sustainable over the long-term. Additionally, there have been a variety of environmental issues raised about fracking in the media and by environmental agencies, which will likely result in increased costs.

Mr. Hanser said that to address these issues of future commodity price forecasting, IFA

took the average of a number of individual forecasts. He noted Ms. Alvey stated the IFA used six publicly available forecasts. Mr. Hanser testified that calculating a simple average of the six forecasts is equivalent to placing an equal weight on their expected accuracy.

It is not reasonable to avoid relying on natural gas forecasts and to obtain future price estimates solely from the NYMEX futures market. Mr. Hanser stated the NYMEX facilitates the trading of futures contracts for natural gas, but, as Mr. Norman points out, the NYMEX exchange data only contains contracts for deliveries through 2023. Mr. Hanser stated that given the SNG Contract starts in 2016, the NYMEX exchange data for actual futures contracts only covers eight years of the thirty-year SNG Contract term, which is less than 30% of the full contract length.

Mr. Hanser testified that although the NYMEX futures prices can be useful as a short-run indication of prices, they are not useful in the context of valuing the SNG Contract. First, the futures contracts are generally for short periods, well short of the thirty-year Contract term. Second, the market becomes very thin the longer the contracting period; that is, fewer and fewer contracts are traded as the contract length is extended. Mr. Hanser noted the amounts that Indiana customers would have to purchase in order to lock in natural gas prices over a thirty-year period are virtually not traded on the exchange.

Mr. Hanser testified he did not rely on Mr. Norman's corrections to the IG model for calculating consumer savings. Using IG's model, Mr. Hanser calculated consumer savings under two principal scenarios: (1) the IG Base Case and (2) a hybrid case, in which the EVA forecast is averaged with the six forecasts used by IG to construct their Base Case (Average IG Base Case + EVA). To calculate the IG Base Case, Mr. Hanser utilized the IG Base Case natural gas forecast in a provided spreadsheet and then calculated the sum of cash flows under the Savings/(Price Increase) to Indiana Consumer line item. Mr. Hanser calculated three distinctive sums of cash flows—a nominal sum of cash flows, a sum of real dollar cash flows (in 2008 dollars), and the present value of cash flows using Mr. Norman's discount rate of 7.5%.

To calculate the second scenario, Average IG Base + EVA, Mr. Hanser used Mr. Norman's spreadsheet provided under DR-41 and averaged in the EVA forecast contained in that spreadsheet with the IG Base Case natural gas forecast to arrive at a new forecast, which is essentially an average of seven distinct forecasts. Mr. Hanser noted Mr. Norman's version of the EVA forecast as contained in the spreadsheet provided under DR-41 is constant in real terms from 2035 until 2045, the last eleven years of the contract. Thus, nominal natural gas prices will increase only at the assumed rate of inflation. Mr. Hanser performed the same calculations of cash flows as he did for the first scenario.

Mr. Hanser found that, using IG's assumed and supported inflation rate of 2.5%, all three scenarios result in savings to consumers. Mr. Hanser reported the results of his calculations using nominal dollar values, 2008 dollar values and present value at the discount rate chosen by Mr. Norman (7.5%). Mr. Hanser noted his experience suggests that the discount rate chosen by Mr. Norman is most likely the upper bound for an appropriate rate. Therefore, given that the precise value of a discount rate is most likely bounded by the nominal value of consumer savings and the rate used by Mr. Norman, Mr. Hanser's findings are robust and clearly show the expected value

of savings to consumers is positive.

Based on the flaws in Mr. Norman's proforma and stochastic models, Mr. Norman's calculations provide unreasonable and unreliable results. Mr. Hanser stated that once those serious shortcomings are properly addressed, the modeling of the SNG Contract can be shown to yield positive consumer savings.

D. Donald W. Maley. Mr. Maley disagreed with Mr. Thumb's assertion that shale has irrevocably changed the energy world. Mr. Maley likened it to past instances in energy and other areas where conventional wisdom developed around a silver bullet that was supposed to change everything, but ended up disappointing, such as nuclear energy and deregulation of the electric industry. Mr. Maley also referred to unanticipated dramatic spikes in energy costs at various times over the past forty years, stating that in these instances, the conventional wisdom of the energy experts at the time was that energy prices would not only remain high but also irrevocably continue to march ever higher. He testified the reality of the marketplace is that the future of energy prices is uncertain and energy projections are always provided based on a set of assumptions about future circumstances. The SNG Contract acknowledges natural gas price uncertainty, the inherent difficulty in predicting future prices and the current risk facing natural gas consumers because of this uncertainty. He stated that if approved, the SNG Contract would disconnect Indiana consumer prices from natural gas markets for about 17% of their natural gas, leaving them exposed to the eventual realities that unfold around shale gas and natural gas prices for the remaining 83% of their supply.

Mr. Maley testified IG is not suggesting that shale gas is not providing an important new natural gas supply, but that great uncertainty surrounds the future of shale gas production. If the current optimistic projections are not realized, the U.S. will be forced to turn to the expensive liquefied natural gas ("LNG") market and compete with growing demand in Europe and Asia for the same resource. Mr. Maley also stated detailed economic analysis performed by experts increasingly questions the rosy economics that some shale gas industry producers have claimed.

Mr. Maley testified there are implications to today's low natural gas prices that Mr. Thumb has failed to discuss, and the appearance of new natural gas resources is creating its own new demand at today's low prices. Because natural gas prices are low today, the Intervenor would have the Commission believe they will remain low and less volatile for the next thirty years. Mr. Maley stated that neither history nor a rational perspective on energy prices supports their view.

The EVA Report does not provide a fair assessment of the environmental concerns for the shale gas industry. According to Mr. Maley, concerns about toxic chemicals leaching into drinking water, radiation contamination in wastewater, excessive water use, greenhouse gas emissions, and industrial development in local communities are likely to pose substantial and increasing challenges to shale gas producers. He stated that, at a minimum, these issues create risk and uncertainty for the continued rapid expansion of shale gas production. If it is confirmed shale gas production has a significant greenhouse gas footprint, then the risk to natural gas consumers from future CO₂ regulation that could increase the cost of shale gas production, which is projected to grow to 45% of the nation's natural gas supply, could be substantial.

Mr. Maley disagreed with the statement in the EVA Report that Arthur Berman has an outlier point of view. While Mr. Berman's views on cost have not been embraced by everyone in the industry, it is a mischaracterization to call his view an outlier. Mr. Maley referred to a speech given by Charles Maxwell,⁵ in which Mr. Maxwell states Mr. Berman's exposition really deserves to be heard and is being heard by a wider audience. According to Mr. Maley, Charles Maxwell is a highly respected voice in the energy sector. Mr. Maley interpreted Mr. Maxwell's references to the extremists as referring to those that take positions on shale gas like those being presented by Mr. Thumb and the EVA Report. Mr. Maley stated Mr. Maxwell makes clear he does not view shale as a game changer.

In response to the EVA Report's assertions that the Bernstein Research price projections are an outlier, Mr. Maley contended that Bernstein Research is one of the most credible and respected independent research groups in the country, and it is used and respected by a broad spectrum of companies and investors.

Mr. Maley disagreed with Ms. Medine's assertion that coal prices have not been and are not expected to be relatively stable. He stated Ms. Medine's entire analysis of coal price volatility is based on spot market prices, but spot market coal purchases represent only about 7% of the purchases made by coal utilities in Indiana and the U.S. as a whole. About 93% of coal is purchased based on contracts that are one to five years in length. Therefore, he said delivered coal prices to major coal users, including Indiana utilities, are relatively stable and show virtually no relationship to the spot market prices that Ms. Medine uses to assert coal prices are volatile.

Mr. Maley testified IG does not plan to buy most of its coal on the spot market. IG developed a fuel procurement strategy with the assistance of Boyd that is consistent with the strategies employed by most large coal purchasers in the market. It involves purchasing the vast majority of coal supplies through contractual commitments of varying duration and quantities and negotiated contractual prices. He said this is the laddered approach referenced by Mr. Weiss.

Mr. Maley disagreed with Ms. Medine's opinion that Indiana coal is unlikely to be the primary source of supply for IG given its ability to take barge coal. IG carefully selected its site to have fuel supply options through delivery by barge, rail, or truck. This optionality will enable IG to negotiate the most favorable fuel supply contracts. The closest supplies of coal will be in Indiana, and IG has a strong economic incentive to use Indiana coal due to the tax credit it will be eligible to receive for doing so. He noted that IG does not have the final say in the coal procurement process, because the IFA has active involvement, input, and authority over the IG coal procurement process to insure that the two objectives of the SNG Project are met: provide competitively priced SNG to the consumer and promote the long-term health and competitiveness of its domestic energy resources.

Mr. Maley testified Ms. Medine should have differentiated between Gulf Coast and

⁵ Mr. Maley stated Charles Maxwell currently serves on the Board of Directors for Chesapeake Energy, one of the pioneering and largest shale gas producing companies in the country, and noted the EVA Report indicated on page 5-11 that the company has been critical of Mr. Berman's work.

Midwest petcoke volatility in her testimony. He stated Gulf Coast petcoke prices are certainly volatile, but Midwest petcoke prices are significantly lower and less volatile than Gulf Coast prices. When petcoke prices are low, IG will be able to contract for petcoke to supplement its coal supply. If petcoke prices are high relative to coal prices, IG will not use petcoke. Consistent with the Midwest petcoke price forecast IG obtained from Jacobs, he said there is every reason to believe IG will have significant opportunities to reduce its overall fuel price by blending petcoke during the SNG Contract's term.

Mr. Maley disagreed with Ms. Medine's statement on page 12 of her prefiled testimony that, "Jacobs treated the Midwest petcoke market in isolation rather than recognizing the ability to export this product through the U.S. Gulf that is currently occurring." IG asked Jacobs to provide a report describing its forecast to show the proper bases for petcoke price forecasts for the SNG Project in Indiana. According to Mr. Maley, the major points that Jacobs made about the petcoke market in its report are consistent with his description.

Mr. Maley testified the price forecast provided by Jacobs is an important part of IG's and the Authority's Base Case economics, and it would be inappropriate to assume away petcoke, which, he stated, would reduce the Base Case economics by \$250 million in 2008 dollars. The SNG Contract enables the IFA to instruct IG to use a higher percentage of petcoke up to 49%. Based on the Jacobs petcoke price forecast, if a 49% petcoke blend is assumed, it increases the projected consumer savings from over \$500 million to over \$1 billion in 2008 dollars in the Base Case. He concluded that the Commission should reject the notion that petcoke would never be an opportunity fuel for the SNG Facility.

The sale of the SNG Facility at the end of the SNG Contract would not be subject to DOE consent because, according to Mr. Maley, the DOE debt will be amortized over the first 26½ years and by year thirty, the DOE debt will have been fully repaid. Mr. Maley disagreed with Mr. Norman's statement that customers pay 100% of any negative Market Differential, but receive only 50% of any positive Market Differential. This ignores the fact that the sharing of positive Market Differential benefits is dictated by whether the cumulative real savings tracking account ("CRSTA") balance is positive or negative and the fact that the initial \$150 million that IG will post at financial closing is available to protect the consumer from negative Market Differential. He also stated that IG is allowed to participate in any positive Market Differential, if and only if, on a cumulative basis over the life of the Contract to that point in time where a positive differential exists, the consumer has received a positive benefit.

Mr. Maley described Mr. Norman's Exhibit RN-2 as misleading because it creates two mutually exclusive thirty-year scenarios and inappropriately combines them in a way that does not account for Market Differential sharing being dictated in the SNG Contract by the balance in the CRSTA. The appropriate way to evaluate the implications of varying gas price is to do so in a single modeling scenario that applies volatility to the price. Mr. Maley offered Exhibits DWM-R13 through DWM-R16 to illustrate the outcomes of varying prices around a breakeven Adjusted Contract Price in a scenario that does not require parallel universes. These scenarios show that Market Differential sharing is not affecting consumer outcomes because the CRSTA balance is what dictates Market Differential sharing. He also noted that in these illustrations, not only does the SNG price remain relatively stable as the natural gas market price varies wildly,

but it actually moves in the opposite direction of the natural gas price and therefore would serve to dampen natural gas price volatility as part of a portfolio.

Mr. Maley disagreed with Mr. Norman's recommendation that a net present value analysis should be used to evaluate the impact of the SNG Contract on Indiana gas customers. A net present value analysis requires an initial investment, and if there is no investment, there cannot be a net value. Under the SNG Contract, there is no investment made by consumers. Mr. Maley stated the correct term for what Mr. Norman is proposing is present value analysis, but that should not be based on the utility-weighted average cost of capital. Evaluating consumer benefits over time on a real dollar basis that adjusts future consumer benefits/costs for inflation is an appropriate means of evaluating consumer benefits from the SNG Contract.

Mr. Maley testified that investors, including IG, are seeking the best opportunities to deploy limited capital resources and typically use a rate of return to compare investments and establish whether a given investment should be pursued. This does not mean that the benefit of the SNG Contract for Indiana consumers should be evaluated by applying a rate of return to calculate a net present value, however. Mr. Maley noted consumers and investors are different groups with different interests that should evaluate things differently. Consumers never use rates of return to evaluate their purchases, whether buying clothes or paying for natural gas delivered by a local utility, but are concerned about inflation and often recognize when the price they are paying for something is higher than it was a few years ago.

Agreeing with Mr. Norman that the major factor driving the value to customers is the future market price of natural gas, along with the future prices for coal and petcoke, Mr. Maley stated that IG and the IFA believe there is considerable uncertainty in the future price of natural gas. Prices are volatile and will remain volatile in the future, and forecasts have been proven completely unreliable due to inaccurate assumptions and unpredictable events that are not in the models. He asserted that in an unpredictable world, shifting a portion of the gas paid for by consumers away from natural gas market prices to a formula-based price that has a fixed capital component, O&M component that moves with inflation, and variable component based on coal (with some petcoke when beneficial) is a sound and beneficial diversification of supply.

As an illustration of the risk currently posed to customers by natural gas prices, Mr. Maley testified pointed to the quantity of natural gas proposed to be purchased by the IFA (38 million MMBtu per year). If there were no SNG Contract, a \$1.00 per MMBtu higher price of natural gas will cost consumers about \$1 billion over the thirty-year period. Consumers own that risk now and currently have the same risk for the other 180 million MMBtus per year of gas they purchase beyond the 38 million MMBtu that would be purchased from IG. On their total gas purchases, a \$1.00 per MMBtu higher price in natural gas, a figure Mr. Maley asserted is a small miss in the context of natural gas forecasts, would cost consumers about \$220 million per year and would cost them approximately \$6.5 billion over thirty years. He said the SNG Contract does not just eliminate some risk to consumers, but diversifies the risk.

Mr. Maley disagreed with Mr. Norman's four changes to the IG/IFA model, stating that: (1) the addition of inflation is duplicative in the case of the field charge and unneeded in the case of the commodity charge and the pipeline reservation charge; (2) the inclusion of power sales

revenue and model revisions of revenue sharing are incorrect, according to the SNG Contract; (3) the changes to ancillary product output in the first two years are duplicative; and (4) the elimination of petcoke from the fuel mix is not reasonable. Other than the elimination of petcoke from the fuel mix, he said Mr. Norman's changes might appear to be relatively minor, but over a thirty-year analysis, even minor assumption changes have an impact. Eliminating petcoke use in IG's Base Case, which assumes a 15% petcoke blend, reduces consumer savings by \$250 million; however, increasing the petcoke blend to 49% increases consumer savings over \$500 million.

Mr. Maley indicated Mr. Norman did not mention his change to inflation in the IG/IFA model, a meaningful assumption change. Without any explanation or discussion, Mr. Maley stated Mr. Norman assumed a lower inflation rate. Mr. Norman did not provide an explanation as to what he considered inappropriate about the IG/IFA model inflation assumption. The change in the inflation assumption from 2.5% assumed by IG/IFA to 1.8% has a significant impact on the analysis, reducing consumer benefits by about \$150 million from IG's Base Case.

He said Mr. Norman incorrectly analyzed consumer savings. Mr. Maley stated Mr. Norman's modeling of the most recent EIA forecast results in negative savings of about \$1.1 billion for consumers in real 2008 dollars. However, when IG includes the EIA natural gas price forecast in its model, allowing for 15% petcoke use and maintaining a 2.5% inflation rate, the result is a negative savings of \$160 million in 2008 dollars, or about \$0.14/MMBtu during the contract.

Mr. Maley disagreed Mr. Norman's characterization that NYMEX futures prices are below the forecasts used by IG and the IFA indicating that those forecasts are outliers relative to the current consensus of natural gas market participants. Beyond three years, the NYMEX is very thinly traded and does not reflect a consensus of market participants. This is because there are financial limitations and risks associated with using the NYMEX to hedge, and very few buyers or sellers are willing or able to expose themselves to these risks and financial requirements. He further stated traders on both sides of a transaction must have collateral to back the positions they take, and the amount of collateral required can change on a daily basis with the market price of natural gas. The risk of these collateral requirements severely limits participation in the NYMEX beyond thirty-six months. If it were even possible to hedge the SNG Project's volumes on the NYMEX, doing so would undoubtedly change NYMEX quoted prices for the hedge. Therefore, to suggest the NYMEX represents a consensus on price or that the NYMEX could be used as an alternative in the SNG Contract is, in Mr. Maley's opinion, a mischaracterization of the NYMEX.

Mr. Maley stated it is not reasonable to believe that IG will be unable to sell the CO₂ as a byproduct and must pay for its disposal. For IG to incur a cost from the regulation of CO₂ implies there is a national CO₂ regulatory program, and IG's sale of 90% of the CO₂ from the SNG Project is inadequate under the regulatory program. Any significant federal CO₂ regulatory program that would impose costs on a facility capturing 90% of its CO₂ would have far-reaching implications for energy prices in the U.S. Mr. Maley testified that no one knows what those implications would be for coal demand and prices. He asserted the single least expensive means of reducing CO₂ emissions under almost any natural gas scenario would be to retire significant

numbers of coal power plants and replace the generation with natural gas-fueled combined-cycle power plants. Mr. Maley stated it is inappropriate to run an analysis that assumes the SNG Facility incurs costs for CO₂ while nothing else changes.

Mr. Maley stated Mr. Norman seeks to focus attention on his preferred scenarios, which apply a low natural gas price forecast, unreasonably alter fuel and other modeling assumptions, and attach Mr. Norman's own unsupported inflation assumption to achieve negative modeling results. Mr. Maley asserted that none of Mr. Norman's negative results in Exhibits RN-6, RN-8, or RN-10, even as uncorrected, would preclude achievement of the \$100 million savings guarantee. Mr. Maley concluded that based on the \$1.8 billion real dollar appraisal value of the SNG Facility at the end of the term established by Mr. Reilly, consumers would still receive \$100 million of guaranteed savings.

Mr. Maley disagreed with Mr. Ulrey's concerns that the SNG Contract produces very little expected savings and thus does not present enough positive attributes to outweigh the very significant cost risks being taken on by the state's gas customers. Mr. Maley noted the savings guarantee, saying it is by no means the upper boundary. He stated Mr. Ulrey's expected savings are a function of Mr. Norman's inappropriate modeling assumptions. He noted the Joint Petitioners testimony supports an expected savings of over \$500 million in real dollars, and there would be another \$500 million if 49% petcoke were used. He contended Mr. Ulrey's position is based on the false assumption that natural gas consumers are currently in a riskless position.

Mr. Maley testified the regulatory path of any future CO₂ regulation is uncertain, but the SNG Facility would be the first coal-fueled plant in the country that can capture 90% of its CO₂ and sell it for use in EOR. It will be better positioned for CO₂ regulation than any coal plant in the country and is likely to become even more economic under a CO₂ regulatory program. If there is CO₂ regulation in the nation, the economics of SNG are likely to improve due to gas demand decreases that reduce coal prices, gas demand increases that raise natural gas prices, and what Mr. Maley contended is the likelihood that the SNG Project will be able to sell excess CO₂ allowances if there is a CO₂ emissions trading program.

Mr. Maley stated the Clean Skies Report does not provide evidence of a consensus and does not represent a broad or unbiased consensus. The Clean Skies Foundation was formed by Chesapeake Energy's CEO, and it serves to promote agendas of the natural gas industry. He stated the Report clearly acknowledges the potential of expanded supply from shale gas, which, it argues, creates significant opportunity to expand the use of natural gas. The Report is focused, however, on providing advice for policymakers to support more stable natural gas prices with an emphasis on hedging and contracting structures to reduce price uncertainty. Mr. Maley stated one recommendation of the Report suggests the right policy choices are needed to avoid adverse effects on natural gas price stability. He asserted this is exactly what Indiana is doing with the SNG Contract. He also testified that the Clean Skies Report recommends long-term contracts as an important hedging tool.

In response to Mr. Ulrey's assertion that the SNG Project runs a significant risk of creating the higher, volatile gas prices it is intended to address, Mr. Maley testified there is clear evidence that the average delivered coal prices of market participants are much more stable than

natural gas prices. Furthermore, coal pricing accounts for only about 40% of the cost of SNG, while the remaining 60% is based on pricing that is fixed today. While there will be some variability in incremental revenues that are shared between IG and the IFA/consumers, the largest portion of incremental revenues is likely to be derived from sales of excess SNG, and changes in those revenues will be caused primarily by changes in natural gas market prices. Incremental SNG revenues will move the SNG price in the opposite direction as natural gas prices, which he contended will serve to directly dampen overall volatility for consumers. Mr. Maley stated IG will be a wholesale supplier of argon and rare gases, not a retail seller, and as such will be able to contract for the sale of those products for up to twenty years with stable formula-based pricing. Even if IG did not contract for these products for some reason, incremental revenues are made up of a basket of byproducts with prices that are not highly correlated. According to Mr. Maley, changes in the overall basket of revenue will be muted by the diversification within the basket.

Mr. Maley disagreed with Mr. Ulrey's assertion that even under a highly favorable set of assumptions the SNG Contract provides little in the way of savings potential to gas customers. He said the Base Case assumptions used by IG and the IFA are not highly favorable but based on independent forecasts for all inputs. The results of the IG/IFA Base Case analysis show over \$500 million of real dollar savings for Indiana consumers. He disagreed with the assertion that coal prices have been volatile and did not believe there is any reliable evidence they will be in the future. He stated coal plants do not have just-in-time delivery of coal, but rather significant coal storage, as will IG, that enables them to adjust their contracted quantities if demand changes.

Mr. Maley also disagreed with Mr. Ulrey's statement that what might have been a reasonable theory ten years ago does not appear to consider where the markets are today. This statement implies there will be no changes in market conditions in the future and suggests that there is not uncertainty. Mr. Maley stated that is inconsistent with the history of natural gas and other commodity prices. Mr. Maley testified that if IG does not have an outlet for its CO₂, the SNG Project will not be built. There is nothing contingent about its plans to dispose of CO₂. With IG capturing 90% of its CO₂, a tax on CO₂ emissions would impact only the 10% of CO₂ expected to be emitted. The ramifications of a CO₂ tax for the price of coal (lower demand, lower price) and natural gas (higher demand, higher price) would benefit the SNG Project's economics. If there is a CO₂ tax, Mr. Maley stated the cost implications for Vectren Energy's coal plants would be more than any cost impact on the SNG Project and could shift some heating customers from electricity to gas.

Mr. Maley disagreed with Mr. Norman's modeling results and his 50% downward adjustment of incremental revenues as described by Mr. Ulrey. Mr. Maley stated IG expects to contract for argon and rare gases and that the marginal cost to produce these products is low. He stated there is a ready market for these commodity products, and IG expects to be the low-cost producer of these products in the U.S. Incremental SNG revenue will largely be a function of natural gas prices and will move the SNG price in the opposite direction as natural gas prices. IG's CO₂ revenue, based on a signed contract, will be a function of oil prices. IG's incremental revenue assumptions are derived from engineering heat material balances that estimate SNG, CO₂, argon, and sulfuric acid production levels and market studies that provide pricing forecasts.

IG subsequently provided both the engineering and market study information to the IFA and Shaw for their due diligence. Mr. Maley further stated the Shaw report discusses and validates the reasonableness of IG's incremental revenue assumptions.

Mr. Maley disagreed with Mr. Ulrey's statement that a hedge at a potential cost of \$1-\$2 billion or more must be scrutinized while keeping in mind burdens on low-income customers and commercial customers. He asserted that a hedge that will help stabilize natural gas prices by diversifying the supply portfolio, reduce consumer exposure to very high prices when consumers are hurt the most, provide potential savings of \$500 million to \$1 billion, and utilize local workers and resources in Indiana rather than sending the money out of state must be considered part of a sound portfolio strategy. The SNG Contract offers a very unique opportunity to hedge a relatively small portion of consumers' gas supply with a long-term contract that is not otherwise available in the marketplace. Mr. Maley further stated replacing future natural gas volatility with future coal volatility for a portion of supply is a very good idea. The assertion that the SNG Project subjects consumers to isolated CO₂ regulatory risks that would not have substantially broader implications is, according to Mr. Maley, a mischaracterization.

Mr. Maley disagreed with Mr. Ulrey's assertion that the SNG Contract is not an effective hedge because the cap price is an unknown. The SNG Contract reduces risk of natural gas price purchased in the spot or short-term markets for consumers. Whether the cap price is known is not dispositive as to whether the hedge has value. The SNG Contract contains a fixed price component in the capital charge and a fixed price component that adjusts with inflation in the O&M charge. Mr. Maley stated that together these components provide considerably greater price certainty than natural gas markets.

Mr. Maley disagreed that gas could be locked in today at prices well below IG's modeled SNG prices for the first eight or more years of the expected SNG Contract. The volume of contracts currently traded in the 2016 to 2023 timeframe is only 7% of the SNG Contract quantity. This light volume suggests that any attempt to hedge the SNG Contract quantity would sizably move the market, and according to Mr. Maley taking such a position requires significant cash collateral. Mr. Maley believed the SNG Contract can be appropriately considered as similar to an insurance policy. It has some aspects similar to insurance because its primary costs are all either fixed or related to non-volatile solid fuel. He further stated this means that the price risk on the high side is bounded, unlike that of natural gas, which is why he considers it an insurance policy.

Mr. Maley addressed other comments made by Mr. Ulrey. Regarding shale gas, Mr. Maley referred to testimony of Mr. Berman and Mr. Bodell and stated that (1) many forecasters take the shale gas investor presentations at face value as opposed to taking the time to look deeper at the costs that are not disclosed in the presentations, (2) many forecasters do not take the time to look at actual well data but use an overall methodology which consistently overstates production and (3) there is a constant mix-up between resources and reserves which serves to overstate future production. Regarding coal volatility, spot prices are only a tiny piece of what is generally a laddered coal purchase plan for utilities and one which IG will be emulating. Mr. Maley stated laddered fuel procurement practices have been shown to produce relatively stable coal prices. The volatility of spot prices will not translate into SNG price volatility. Regarding

petcoke, Mr. Maley viewed it is an opportunity fuel. Volatility in petcoke prices means that sometimes the price is up and sometimes down. IG will use petcoke during the down times.

Mr. Maley also disagreed with Mr. Ulrey as to the issue of CO₂ pipeline costs. Mr. Maley stated CO₂ pipeline costs will be addressed through commercial arrangements between IG and the pipeline company. There are no provisions in the SNG Contract for Indiana consumers to pay any of these costs, so CO₂ pipeline costs have no impact on the SNG costs to consumers. The costs that are netted out of CO₂ revenues under the SNG Contract are costs related to the compression of CO₂, which are only netted and recovered to the extent there is a sale of CO₂ that generates revenue. The SNG Contract provides a \$0.51 per MMBtu cap on the net cost to consumers if the CO₂ sales revenue is not sufficient to cover these costs. In the event that there is a change in governmental requirements to implement CO₂ regulation that adds mitigation costs to IG, the cap of 13.5% of the SNG Adjusted Price will come into play.

Mr. Maley disputed Mr. Ulrey's belief that the SNG Contract fails to provide for guaranteed savings as provided under the SNG Statute. The collateral for the \$100 million is a security interest in the assets of the SNG Facility that will cost over \$2.5 billion to construct. Over the term of the SNG Contract, the debt will be amortized so that by the end, all debt will be retired and IG will own the SNG Facility free and clear of original debt. He said the appraised value of the SNG Facility at the end of the term is expected to range from \$1.5 billion to \$1.8 billion. The SNG Facility will be pledged as collateral for IG's guarantee to cover a cumulative negative differential, if any, between SNG and pipeline natural gas over the life of the SNG Contract plus a net savings of \$100 million.

IG's negotiations related to the third-party marketing agreement so far have indicated that IG will be paid based on monthly or daily indices, with no discount. Mr. Maley did not believe it was the case that there will be an effect on the price of SNG sold from the SNG Project because the supply will not be as reliable as the natural gas supply. Mr. Maley disagreed with Mr. McCullough that it would be easy to buy NYMEX futures as an alternate hedge to the SNG Contract. Trying to buy NYMEX futures in the volumes equivalent to that produced by the SNG Project—nearly fifteen times as great— would obviously move the market. He said outside of the near term, the NYMEX market is not a forecast of future natural gas prices, but merely a reflection of what a small group of buyers and sellers is currently willing to buy and sell for their respective positions. Mr. Maley believed that purchasing NYMEX futures of this magnitude would require a substantial period of time to put in place.

Mr. Maley testified Mr. McCullough is correct in describing the requirement to set aside debt service every month before the sharing of incremental revenues. This has been a very important provision vis-à-vis the DOE and their analysis of the financeability of the SNG Project. Mr. Maley stated, however, that Mr. McCullough overstates its importance to the analysis of consumer savings. Mr. Maley noted that based on analogizing to the Duke Edwardsport plant, Mr. McCullough leaps to the conclusion of a median expectation of a 45% cost overrun, some portion of which would be funded with debt. Mr. Maley testified Mr. McCullough's analysis is wrong because the SNG Project is a substantially different technology than an IGCC plant like Duke's. Additionally, Mr. McCullough's analysis disregards the conclusions put forth by Mr. Kuhr that corroborate IG's cost estimates, and the analysis ignores

such issues as a fixed \$3.50 per MMBtu capital charge and the required prospective debt service coverage ratios that are critically important to a project finance lender. Finally, the only debt service shortfall that could result in the use of the IFA's incremental revenues to help pay debt is one associated with DOE-guaranteed financing. Mr. Maley testified he can say with confidence that the DOE will not guarantee additional debt to help cover any construction cost overrun.

Additionally, he testified the DOE will not close on IG's financing unless it is satisfied with the level of capital costs and the sources of that capital. He stated IG is in the process of significant due diligence on this issue, having hired Sargent & Lundy as Independent Engineer. The SNG Contract itself does not allow any increase in debt without prior approval by the IFA. If there are cost overruns, the DOE will fully expect the owner to fund any cost overruns with equity funding. Mr. Maley testified Mr. McCullough's use of a 6.04% discount rate in his analysis is not appropriate. Mr. Maley stated he can assure that IG, not to mention the DOE, would not provide financing of a project if believed there was a probability or likelihood of significant cost overruns. If there are overruns, the amount of the debt that would affect SNG Contract incremental revenue sharing would not change. He also stated the DOE minimum coverage ratio will not allow for additional debt, and the overrun risk is born by the owner and lender, with no residual risk to the consumer.

Mr. Maley disagreed with Mr. Blair's characterization of the status of the SNG Project with the DOE. The work on the Environmental Impact Study ("EIS") has been waiting for the submission of IG's permit application in the state of Indiana. Now that the permit application has been filed, work on the EIS will continue. Mr. Maley testified IG will not abandon the SNG Project after spending the DOE-guaranteed debt dollars. The DOE will not commit its debt guarantee and agree to financial closing unless it is satisfied with the projected capital costs of the SNG Project, including an appropriate amount of contingency, and until the sources of capital for the entire capital cost of the SNG Project are secured. Funds are committed up front to remediate the site if, in fact, the SNG Facility never achieves commercial operations.

Mr. Maley disagreed with Mr. Marcus's characterization of the savings guarantee under the SNG Contract as unfunded and optional. He explained how IG will fund the guarantee if not realized during the term of the Contract. He also disagreed with Mr. Marcus's description of Leucadia's potential profit from the SNG Project and stated the \$3.99 billion Mr. Marcus calculates must service debt and equity.

Mr. Maley indicated the growth rate testimony of Mr. Stenger is inaccurate. Mr. Maley disagreed with Mr. Stenger's approach that one should take various energy prices at one time and escalate them at the same rate for the next thirty years. Mr. Maley also disagreed with Mr. Stenger's testimony concerning volatility. Coal prices shown on the unrevised Exhibits JTS-1 and JTS-2 are too high. Mr. Maley testified Exhibits JTS-1 and JTS-2 illustrate there is substantial volatility in the prices of oil and natural gas and relatively little volatility in coal. According to Mr. Maley, Mr. Stenger's data, even though flawed, actually supports Mr. Maley's underlying assertion that Indiana consumers would enjoy reduced volatility in their natural gas costs by having a portion provided under the SNG Contract.

Mr. Maley testified there is inconsistency in Mr. Stenger's testimony when he at one

point says that the EIA projections merit consideration while criticizing IG's coal projections as low because IG's coal projections come from the EIA. Mr. Maley testified Mr. Stenger's analysis is flawed. According to Mr. Maley, Mr. Stenger's testimony as originally filed did not increase the value of the \$150 million CPR by inflation and failed to include gas basis differential and transportation charges.

Mr. Maley disagreed with Mr. Stenger's assertion that in the Low Case model, IG receives a large fixed margin after debt service. Mr. Maley noted that a large portion of the fixed margin identified by Mr. Stenger occurs in the last 3½ years after the DOE debt is paid down. He testified that this fixed margin is not assured and depends on IG's costs in operating the SNG Facility and its success in selling output. The SNG Contract has been structured so that IG makes only a very minimal return if the consumer is not getting a good deal. In the Low Case, IG earns a single-digit return. Mr. Maley disagreed with Mr. Stenger's assertion that Indiana consumers subsidize the SNG Project by paying for the DOE loan guarantee and because the SNG Contract is not likely to be providing savings. Mr. Maley stated that first, the DOE loan guarantees for fossil projects, unlike for the later renewable solicitations, are self-funding. He stated IG must pay an up-front credit subsidy fee from equity as part of the financial closing.

Mr. Maley disagreed with Mr. Kerney's description of the charges passed on to Indiana consumers as subsidization of investment by a private, non-regulated entity—Leucadia. Mr. Maley agreed that IG is private, but its prices, if the SNG Contract is approved by the Commission, will effectively have been approved by the Commission, i.e., regulated in a sense. Subsidization implies that IG has gotten some kind of financial break, which he contended is not the case. The price the IFA will pay IG is based on a cost structure that has been verified by Shaw. He noted IG will earn a larger profit when the consumer prospers. There is no subsidization by the State—only a long-term contract that, according to Mr. Maley, enables lower costs and longer amortization of long-term debt, all of which he stated will go back to lowering the price to the consumer.

Regarding Mr. Shambo's request for a technical conference, Mr. Maley testified that a UMA under Section 7.2 of the SNG Contract must be in place within ninety days after a Commission Order approving the SNG Contract is issued. Mr. Maley believed the DOE will require the billing and collections provisions in the UMA, as well as the timing and mechanics of billing and collections, to have been sufficiently finalized and agreed upon between the parties to the UMA in order for the DOE to review the financial model, confirm working capital needs, assess risks of delay, and revenue and receipts. Mr. Maley stated while administrative details, such as the physical delivery of SNG during emergency situations as contemplated in the SNG Contract, can be worked out at a technical conference, the overall concepts and timing related to billing and collections must be finalized in sufficient detail before the completion of the conditional commitment later this year. Mr. Maley additionally stated the UMA is to be collaterally assigned to IG to secure the payment obligations of the IFA under the SNG Contract, so the final form and substance of the UMA must be reviewed and approved by the Commission before the initial conditions precedent deadline, and well before the anticipated financial closing date of June 2012.

E. **William G. Rosenberg.** Mr. Rosenberg addressed Mr. Ulrey's opinions

concerning prerequisites for Commission approval of the SNG Contract. He stated that while Mr. Ulrey agreed with Ms. Alvey's description of the Commission's role in this proceeding (i.e., to approve the SNG Contract if it is in compliance with the requirements of the enabling legislation), Mr. Ulrey's view of the Commission's role involves a two-step review process. Mr. Ulrey proposes that in addition to finding the requirements of the SNG Statute relative to approval of the SNG Contract have been met, the Commission engages in a public interest review of the entire SNG Project.

The SNG Statute requires only that the Authority shall submit a final purchase contract to the Commission for approval. Mr. Rosenberg stated it does not require or suggest de novo Commission review of the negotiations and terms, the give-and-take inherent in such negotiations, or the final terms that result following consultation with the OUCC if all statutory requirements are met. He testified the circumstances here, and the spirit and letter of the SNG Statute, impose a much different Commission responsibility and role in this proceeding than it must satisfy or undertake in, for example, a rate dispute between a utility and its customers or a territory dispute between two utilities.

Mr. Rosenberg believed the Commission must make certain public interest or public convenience and necessity findings for IG's construction and performance under the SNG Contract. The Commission must make such a finding relative to the SNG Project's use of clean coal technology and the associated tax credit authorized by Indiana Code ch. 6-3.1-29. He further stated the enabling legislation for the tax credit requires a taxpayer applicant such as IG to "obtain from the commission a determination under Indiana Code § 8-1-8.5-2 that public convenience and necessity require, or will require: (A) the construction of the taxpayer's integrated coal gasification powerplant" Mr. Rosenberg stated Mr. Maley's testimony concerning the SNG Project generally, and its intended use of clean coal technology, supports such a determination. Mr. Rosenberg testified that the request for that determination is not incongruent with IG's request for the Commission to decline to exercise jurisdiction over IG under Indiana Code ch. 8-1-8.5 because that statute has to do with the certification required for public utilities to build new electric generation facilities. He said that certification is intended to protect retail customers of regulated utilities from the costs associated with excessive generating capacity, but also ensure that public utilities could recover their investments in generating capacity, i.e., to transfer construction risks to the consumers.

Mr. Rosenberg disagreed with Mr. Blair's assertions that the SNG Project apparently cannot function under normal, free enterprise business models and, thus requires significant public resources to both accumulate capital for construction as well as to market the end product. Energy services are typically provided by regulated franchise monopoly utilities, not free enterprise. Mr. Rosenberg described the business model under which the SNG Project is being developed as a "hybrid" that involves some aspects of a regulated utility business model, such as the Commission's role in this Cause, and some aspects more akin to a free market, such as a substantial private equity investment and the assignment of construction and operating risk to the SNG Project's investors, rather than ratepayers. He stated this structure provides for simultaneously achieving low-cost financing and apportioning risk to protect ratepayers from construction and operating risks.

F. **Joseph S. Hezir.** Mr. Hezir is co-founder of the EOP Group, Inc., a Washington-based consulting firm. For the past year, he has been a Lead Analyst as part of the MIT Energy Initiative study team working on a project concerning the future of natural gas. Mr. Hezir testified concerning projections of future supply and costs of natural gas, including potential implications of environmental issues associated with shale gas production. Current EIA projections are subject to considerable uncertainty, and the price projections are likely to be too optimistic. He also made observations regarding the impact of potential future requirements for CO₂ emissions and the impacts on natural gas markets. He stated future CO₂ will provide a cost advantage to SNG supplies that have already taken into account carbon capture and storage.

According to Mr. Hezir, the phrase game-changing shales contained in Mr. Thumb's testimony and the EVA Report is an overstatement because the term implies a fundamental shift in energy markets, which does not appear to support the evidence. The MIT Interim Report concerning the future of natural gas concludes that unconventional gas, and particularly shale gas, will make an important contribution to future U.S. energy supply and CO₂ emission reduction efforts. Mr. Hezir stated it goes on to discuss multiple uncertainties about the supply picture and suggests that much remains to be learned about the performance of shale gas plays in the U.S. and other parts of the world.

Mr. Hezir said the lack of complete information from environmental problems stemming from hydraulic fracturing does not permit a definitive answer to the issue of environmental impacts. More detailed assessments are required, as well as improvements in best management practices, and additional R&D on water management technologies. In the MIT Interim Report, Mr. Hezir reviewed reports of several hundred cases of alleged environmental problems associated with hydraulic fracturing operations. The MIT Interim Report summarizes four areas of environmental concern: (1) risk of shallow freshwater aquifer for contamination with fracture fluids; (2) risk of surface water contamination from inadequate disposal of fluids returned to the surface from fracturing operations; (3) risk of excessive demand on local water supply from high-volume fracturing operations; and (4) risk of surface and local community disturbance due to drilling and fracturing activities.

There is a significant likelihood there could be new environmental requirements that could lead to less shale gas production, higher costs, or both. There are four areas in particular that Mr. Hezir believed illustrate the risk to shale gas associated with environmental concern. First, there is a regional, state, and local moratorium that will limit growth of shale gas production. Second, the EPA is initiating a detailed life cycle study of shale gas from which conclusions will not be available for at least another year. Third, the new EPA methane emissions inventory has significantly increased the estimate of global warming potential from shale gas production. Fourth, the EPA and the Pennsylvania Department of Environmental Protection ("Pennsylvania DEP") are conducting detailed monitoring of water quality impacts, including radioactivity, of wastewater disposal from shale gas production.

Mr. Hezir testified that moratoria on shale gas production are currently in effect for all of New York State and the areas of Pennsylvania and New Jersey under the jurisdiction of the Delaware River Basin Commission. In addition, the cities of Buffalo, New York, and Pittsburgh, Pennsylvania have established drilling moratoria within their jurisdiction. On February 8, 2011,

the EPA released a draft study plan for a multi-year research program on hydraulic fracturing, which proposes a comprehensive, life cycle evaluation of the water quality issues associated with hydraulic fracturing with the key questions organized around five areas: (1) water acquisition; (2) chemical mixing; (3) well injection; (4) flowback and produced water; and (5) wastewater treatment and waste disposal.

The new EPA methane emissions inventory significantly increased the estimate of global warming potential from shale gas production, and the EPA published new data on U.S. greenhouse gas emissions in February 2011 that doubled the estimate of methane emissions from natural gas systems from the previous estimates compiled in 2008. Mr. Hezir stated the doubling was associated with hydraulic fracturing associated with unconventional natural gas production. He noted there is significant controversy over these estimates, and one analysis estimated the effect of methane emissions from non-conventional gas results in a doubling of the national total amount of methane leakage from natural gas operations. The natural gas industry challenged these findings, indicating the potential for reduced emissions completion technology to reduce methane emissions from shale gas production by 90%. However, Mr. Hezir stated there is no indication as to the extent that reduced emission completion technologies are being implemented and no estimate of the impact of these technologies on the cost of production.

The EPA and Pennsylvania DEP are conducting detailed monitoring of the water quality impacts (including radioactivity⁶) of wastewater disposal from shale gas production. On April 19, 2011 the Pennsylvania DEP issued a voluntary order requesting shale gas producers to stop discharging shale gas wastewater to sixteen designated municipal sewage and commercial treatment plants. While this action may not result in stoppage of current shale gas production operations, it likely will increase the cost of production and may slow down plans for deployment of new wells. Regarding Mr. Thumb's dismissal of the potential impact of concerns about hydraulic fracturing, Mr. Hezir said all of these new developments – New York State and New Jersey positions, the new EPA methane emissions inventory, the EPA life cycle study and the Pennsylvania DEP actions – were not factored into earlier projections of shale gas production and cost estimates. He stated that while it is not possible to forecast with certainty the impacts of these actions on future shale gas production, it appears likely that shale gas will come under more stringent environmental regulation. He concluded as a result, shale gas producers will need to consider additional environmental mitigation measures and these will increase the cost of production and, in some cases, may deter new drilling.

Mr. Hezir disagreed with Mr. Ulrey that an abundance of gas supply will be available at low, stable prices for many years into the future. He stated that supply is a function of price, and future prices will be determined by the interplay between supply and demand. He stated that abundant supply does not necessarily guarantee a low, stable price; rather, the price of natural gas is dependent upon both the level of supply and level of demand. He testified that in order to fully understand the potential impacts on natural gas prices, it is necessary to understand both the net addition to domestic natural gas supplies resulting from shale gas and the potential changes

⁶ Mr. Hezir stated the Marcellus shale formations contain naturally occurring radioactivity and preliminary indications are that this radioactivity is being brought to the surface mixed in with the hydraulic fracturing fluids.

in demand from that gas and how it may increase the bid concerning the price.

Mr. Hezir said he would approach this analysis in three steps: first, a presentation of the estimated costs associated with the increase in supplies of shale gas; second, an estimate of the net increase in U.S. natural gas supply, taking into account other changes in domestic supply; and third, the potential increased demand for natural gas and its effect on the market equilibrium. He noted future levels of shale gas supply will be dependent upon production costs and that there have been many recent reports regarding the potentially large size of the shale gas resource base. The MIT Interim Report provides two caveats with respect to estimated resources. First, while the report notes that the new shale plays represent a major contribution to the nation's resource base, it also notes there is considerable variability in the quality of the resources, both within and between shale plays. Second, production estimates from shale gas are challenging because the shale gas production from individual wells declines at a rapid rate.

Mr. Hezir testified that based on an analysis of the potential supply curves for shale gas, the MIT Interim Report states that a substantial portion of the estimated resource base is economic at prices between \$4.00 per mcf and \$8.00 per mcf. However, Mr. Hezir noted it becomes difficult to project how much of the future supply volume can be produced at the lower end of this range, and how much is dependent on market prices at the upper end of the range. These costs are production costs at the wellhead and other factors will add to these cost estimates, such as company overhead costs, additional processing and transportation infrastructure costs, adjusting the estimates (which are in 2007 dollars) to current dollars, and likely increased production costs resulting from additional measures to reduce environmental risk. Increased shale gas production will not add to U.S. natural gas supply on a one-to-one basis. Mr. Hezir noted that while the production of shale gas has increased, some of that shale gas supply is simply replacing declining natural gas production from conventional sources and from imports.

Additionally, increased demand for natural gas for existing and new applications will increase the price, and there are a number of potential opportunities to expand the use of natural gas in existing and new applications. Mr. Hezir stated that because many of these activities are still in their formative stage, they are not reflected in current supply and demand projections such as the EIA AEO 2011. As part of his work on the MIT future of natural gas study, Mr. Hezir is in the process of preparing a new report with estimates of potential future demand that include the ability to use: (1) up to 4 TCF per year of additional demand for natural gas to increase the level of electricity generation for existing natural gas combined cycle generation facilities; (2) up to 0.9 TCF per year of additional demand for natural gas to replace existing coal industrial boilers; (3) up to 1.7 TCF per year of additional demand for natural gas by 2035 in industrial combined heat and power systems; (4) up to 2.5 TCF per year of additional demand for natural gas for transportation applications. He added an even greater potential demand exists for conversion of natural gas to liquid fuels that can be used directly in current vehicles with little or no modification. According to Mr. Hezir, this increased demand for natural gas would lead to a higher price that will balance the increased supply with the increased demand. The combination of increased costs of production and increases in demand for natural gas will lead to higher prices than some analysts currently project.

Mr. Hezir testified that contrary to Mr. Ulrey's assertion, it is not likely the reduced gas prices and dampened price volatility that have occurred as a result of shale gas can be sustained while global market prices are much higher. Mr. Hezir stated continued development of a global transportation system for LNG has the potential to create a single global market for natural gas, just as the evolution of supertankers contributed to a single global market for oil. Because of the current differential between the price of natural gas in the U.S. and prices in other regions, companies are exploring the feasibility of converting LNG import terminals into export terminals. Mr. Hezir believed exports of natural gas are another form of increased demand, and thus will put upward pressure on prices and potentially tie U.S. natural gas markets more closely with global markets.

In Mr. Hezir's view, EIA price projections, while useful for certain analytical purposes, do not represent a sound basis for making multi-billion dollar investment decisions. Historically, there has been substantial variance between EIA projections and actual results. Also, there are significant differences between current EIA projections and other reputable sources. He further stated the natural gas market has experienced periods of significant natural gas price volatility over the past decade that neither can be explained nor otherwise accounted for in EIA projections. The EIA AEO is used for analytical purposes because it provides comprehensive coverage of all energy markets. However, Mr. Hezir noted it is not a forecast, and its past ability to predict prices is poor.

Mr. Hezir stated federal regulation that places a price on CO₂ emissions, directly or indirectly, would increase the price of natural gas significantly. Also, it would make the price of SNG significantly more attractive than natural gas because the cost of CO₂ capture would already have been built into the cost of production of the SNG. Mr. Hezir stated that under any reasonable scenario of future regulation of CO₂ emissions, consumers of SNG would benefit relative to consumers of coal or consumers of natural gas. Because the CO₂ associated with the conversion of coal to SNG is incorporated into the SNG Project from the outset, he said the SNG Project will be insulated from many future cost increases from CO₂ regulation. By comparison, the cost of coal processing to reduce CO₂ emissions, either pre- or post-combustion, would increase substantially. He noted if the price of SNG were controlled under some form of long-term contract, the price of SNG would not increase with the projected increase in the market price of natural gas, and consequently, consumers of SNG would enjoy lower prices for gas relative to consumers of natural gas.

G. John L. Weiss. Mr. Weiss agreed with Ms. Medine that there has been an increase in the volatility of spot market coal prices since 2001. The movements of spot market prices are entirely related to the fundamental economic laws of supply and demand. Over the past decade, the balance between supply and demand has been delicate, which is reflected in the upward and downward movements of spot market prices in comparison to the prior two decades. Mr. Weiss noted that Ms. Medine does not offer any information about the average annual coal costs incurred by large buyers over the last decade. He stated she is instead focused only on the spot market and the volatility of spot market prices, which is not indicative of the average price paid for coal by consumers and not representative of IG's future annual coal costs.

Mr. Weiss testified the vast majority of coal used for generation of electricity is bought

and sold in the United States through coal supply agreements of varying duration. He further stated these contracts are generally executed between the coal mine operator and the consumer. They negotiate contractual prices, coal quality specification, transportation arrangements, terms and conditions. Mr. Weiss testified IG will purchase coal under similar arrangements. Of the almost 941 million reported tons delivered to the nation's electric power industry in 2010, only about 63 million (6.7%) were classified as spot sales. Mr. Weiss noted that similarly, a subset of the same data shows 2010 spot purchases at Indiana generating stations comprised 7.4% of the total tons delivered.

While IG would likely make occasional spot purchases, it has no intention of attempting to meet any meaningful portion of its feedstock needs by relying upon spot market purchases. Instead, Mr. Weiss stated the vast majority of IG's coal would be purchased via contractual commitments of varying duration and quantities with negotiated contractual terms. Forward prices, as reported by traders of publications, are not representative of what IG will have to pay for its coal.

According to Mr. Weiss, there is a relationship between contract prices and spot market prices. Mr. Weiss explained the prices for new coal supply agreements and market re-openers associated with existing agreements generally reflect market trends because coal buyers and sellers comprehend the nature of market forces and competition. However, few contracts are priced at maximum or minimum prices during times of market extremes. He said contractual prices and terms are frequently negotiated during the weeks or months prior to the actual execution of the contract. Accordingly, the prices for such contractual arrangements may or may not be consistent with reported market prices of coal trades on various exchanges identified in industry publications. Mr. Weiss stated the average coal price of a prudently assembled portfolio of contracts will not resemble the forward price curves and will be smooth when compared to spot market prices.

Mr. Weiss disagreed with Ms. Medine's opinion that if natural gas-fired electricity generation increases, thereby displacing some portion of coal-fired electricity generation, this would contribute to a higher degree of volatility in coal prices. Mr. Weiss did not believe there is evidence that coal will be displaced by gas, but if this situation occurred, he would expect lower coal prices and minimal price volatility. A reduction in coal demand would contribute to an oversupply of coal, which would contribute to low coal prices. Mr. Weiss noted this situation was demonstrated throughout the 1980s and 1990s when there was an oversupply of coal in the nation relative to demand, and the price of coal declined throughout this period.

Variable coal burn and corresponding changes in delivery schedules would likely contribute to price volatility. However, Mr. Weiss noted that in practicality, such a scenario of variable consumption and delivery patterns will not occur. Coal producers cannot start and stop coal mining operations in response to periodic variations in demand. Also, a prudent coal consumer who expected short-term fluctuations in coal consumption would maintain appropriate coal inventory as a tool to manage such variations. Mr. Weiss stated that, in recognition of these considerations, coal supply agreements would reflect annualized coal consumption and not variations in periodic deliveries.

Mr. Weiss disagreed with Ms. Medine's statement that the EIA long-term forecast for coal does not capture anticipated price volatility, and asserted long-term forecasts capture anticipated price volatility. The most important component of a long-term forecast is the assumption that market forces will eventually be in balance; producers and consumers will adjust to markets. He stated there is absolutely no doubt that the spot market for coal will experience volatility in short periods.⁷ However, in the long-term these factors are irrelevant, and the recognition of short-term price volatility is why prudent coal consumers will execute a laddered contract approach that provides security of supply and coal predictability.

In Mr. Weiss's opinion, there are many factors that influenced the selection of Spencer County as the location for the SNG Facility. The site offers a dependable source of water, access to power lines and gas pipelines, and reduced capital expenditures for initial construction. In Mr. Weiss's opinion, the ideal site location is one that optimizes the balance between minimum fuel supply costs and maximum reliability of fuel supply, while achieving relatively low levels of operational and financial risk. He concluded the proposed Spencer County site is ideally suited to meet these goals and is a logical and appropriate location for IG based on fuel supply parameters.

Mr. Weiss added the Spencer County location is close to significant undeveloped blocks of coal reserves in southern Indiana and within acceptable haulage distances from active coal mining operations throughout the State. The site's proximity to virtually all coal production in Indiana will be beneficial in promoting competition between not only the Indiana coal producers, but also the trucking and rail entities that transport coal from active mines to end users. Mr. Weiss stated the selected site's location along the Ohio River will enable IG to procure coal via low-cost barge transportation from numerous mines elsewhere in the Illinois Basin, which will further promote competition. Mr. Weiss stated IG is constructing the site to have maximum flexibility in fuel sourcing and transportation, including barge delivery.

At full capacity, IG's estimated annual coal requirement of 3.5 million tons is not too large to deliver by truck. Mr. Weiss noted many large coal consumers receive a portion or all of their coal by truck, and the determining factor is what makes the most practical and economic sense from security of supply and delivered cost standpoints.

Mr. Weiss believed there are ample coal reserves in Indiana to meet the coal demands of existing consumers and new market participants such as IG. In his opinion, the availability of other Illinois Basin reserves demonstrates the security of fuel supply is further enhanced. The specific sources of coal will be dependent upon contractual negotiations as the SNG Project progresses. Mr. Weiss stated the delivered cost of Indiana coal to IG will be competitive with the delivered costs of coal from Illinois and western Kentucky. He does not believe the Ohio River location will likely result in use of non-Indiana coal, but IG has assembled a plan to procure coal from multiple sources in a reliable and cost-effective manner.

He testified exported petcoke competes with other fuels in the international marketplace

⁷ Mr. Weiss noted coal production, transportation and consumption will be influenced in the short-term by issues such as weather, railroad congestion, barge availability, river flooding, economic activity, costs of competing fuels, problems at mines and power stations, and currency exchange rates.

on a delivered price basis. Typically, if a refinery is located near a port of export (i.e., near the Gulf of Mexico) and has the ability to produce petcoke, that product will likely sell at prices more akin to international prices. But, Mr. Weiss stated, if an interior refinery is selling petcoke to a local customer, it will likely sell the petcoke at a delivered price that is competitive with other competing fuels.

Mr. Weiss stated Ms. Medine's opinion future petcoke prices does not reflect future volatility and does not recognize that petcoke, as a byproduct, tends to be produced at relatively consistent levels of annual output, while demand and associated consumption change periodically. He stated this is why petcoke prices move upward and downward more than coal. Mr. Weiss stated Ms. Medine's assertion the price of petcoke will be set by the global price of coal is in direct contraction to her petcoke price forecast in EVA Exhibit 7. He noted Ms. Medine is critical of the EIA long-term forecast because it does not capture volatility, yet her petcoke forecast does not include volatility. He also noted volatility in petcoke pricing does not preclude using a contrast laddering approach toward purchases, and the basis of a laddering approach is to provide security of supply and compensate for volatility.

Petcoke production, rather than petcoke demand, is a function of refining activity. The price of high-sulfur petcoke will reflect the supply/demand balance for that specific product. Mr. Weiss stated when there is a surplus of high-sulfur petcoke, the price can and does drop precipitously, and petcoke prices may be lower than coal prices.

With respect to Ms. Medine's assertion that there is a specific global market price of coal which sets the standard for petcoke prices, Mr. Weiss stated she appears to mean the Amsterdam-Rotterdam-Antwerp ("ARA") price of coal and/or petcoke is the definitive driver of Illinois Basin coal prices, and therefore the price of the petcoke delivery within the Ohio River region. Mr. Weiss noted that on occasion, during brief market periods when there are shortages of fuel and when market prices reach historical peak, this scenario can happen. However, he noted that for the vast majority of the time, ARA pricing does not enter into the equation of Midwestern coal and/or petcoke pricing. Instead, he said the prices of coal and/or petcoke deliveries to Illinois Basin customers are driven by local competition for fuel and associated transportation.

H. Arthur E. Berman. With respect to testimony provided by Mr. Thumb and others regarding the effect of shale plays on natural gas supply and price issues, Mr. Berman stated these witnesses summarized investor presentations made by the various companies engaged in shale plays without questioning or investigating the truth or basis of their claims.

The words resource and reserve are not interchangeable; Mr. Berman said there is an important difference between resources and reserves, and between reserves and supplies. He explained a resource is an estimate of total natural gas in place, only a small portion of which is recoverable. A resource may be estimated even if no well has been drilled to test if there is gas present. A resource includes all gas regardless of whether it is commercial. Mr. Berman stated there is great uncertainty in a resource estimate. A technically recoverable resource is the portion of the resource that it is possible to recover and is also highly uncertain. An economically recoverable resource is yet another smaller subset of the technically recoverable resource.

A reserve, also called a proved developed reserve, is the portion of the economically recoverable resource that has been unequivocally shown to exist by the drilling and testing of a well. Mr. Berman stated a reserve is limited to the drainage area of that well. Areas or spacing units adjacent to the proved developed reserve that can be reasonably inferred to have similar volumes of gas as the unit which is tested by a well are called proved undeveloped reserves. He stated this category has considerable uncertainty because lateral variations in reservoir quality, trap, seal, or charge may limit the size of the proved undeveloped reserve. Supply is the portion of a reserve that has been produced and is available for sales and use. Due to the time it takes for field development and construction of pipeline and treatment infrastructure, he said it may take many years from discovery and booking of reserves before the first oil or gas is produced.

Mr. Berman said, contrary to Mr. Thumb's assertion, his assessment does not misconstrue the prolific nature of the shales and their economic viability. Mr. Berman testified he agrees the size of the shale gas resource is large, but he also believes there is compelling evidence that results to date are not commercial. Shale gas reserves are also overstated because incorrect models and assumptions have underestimated shale well decline rates. Shale gas reserves have already been written down by more than \$60 billion from 2008 to 2010, which will continue to be revised, as depicted in Exhibit AEB-R2. He also stated that much of what has been booked as proved reserves are undeveloped, and company disclosures suggest many of these undeveloped reserves will not be commercially developed in the future. According to Mr. Berman, those who advocate that shale gas is economically viable exclude significant costs, including land acquisition, debt service, general and administrative expenses, dry hole costs, and plugging and abandonment expenditures.

Mr. Berman said he is not mistaken concerning the current nature of gas price volatility. Further, he does not use an outlier price projection to present a view on future gas prices that is far from the industry consensus. According to Mr. Berman, natural gas price volatility is not an opinion but a fact based on historical data. Price projections by the EIA and most other organizations have been incorrect in the past, which he said casts doubt on the reliability of their present projections of low future prices. Mr. Berman contended, based on five years of stated costs and 10-K SEC filings by the principal companies involved in the shale gas plays, that the average marginal cost to find and produce shale gas is \$7 per mcf. Mr. Berman stated 10-K costs are provided under penalty of the Sarbanes-Oxley Act, so it is reasonable to believe they are correct.

Mr. Berman testified he correctly excluded from his analysis of the concepts of the marginal producer and the statistical effect poor producers have on raw data, which is not inconsistent with standard economic evaluation practice. Mr. Berman evaluated the top six Barnett Shale operators and found that their average economic ultimate recovery ("EUR") ranges from 1.0 to 1.5 billion bcf, but that the commercial minimum economic threshold ("MET") or break-even production level for a Barnett Shale well is 1.5 bcf at \$6.25 per mcf netback gas price, nominal land costs, \$3 million D&C costs, \$1.20 LOE and corporate general and administrative costs ("G&A") costs, and a 10% discount factor. Only one of the top six operators achieved this MET, but Mr. Berman noted this only means it has paid all its costs but not made a profit.

While he agreed with Mr. Thumb that the various shale plays have geological differences, he disagreed that commercial results cannot be compared. Mr. Berman acknowledged each play has different costs and therefore a different MET, but stated commerciality can be assessed and compared. According to Mr. Berman, the main concern is to determine if the various shale plays will make money.

Mr. Berman disagreed with Mr. Thumb that ExxonMobil's entrance into shale development indicates there will be low natural gas prices. ExxonMobil's investor presentations consistently stress that the company sees significant growth in natural gas demand in the future. Demand will increase price, and according to Mr. Berman, that is ExxonMobil's primary driver for play entry and maintenance. Another key reason for ExxonMobil's decision to become involved with shale plays is reserve replacement. He testified the company has faced increasing difficulty over the past decade in meeting its reserve replacement objectives as international opportunities have become less attractive. According to Mr. Berman, all the major oil companies, including ExxonMobil, recognized the gas potential of shales decades before drilling and development activities began. He stated they chose not to pursue the plays until recently because of unfavorable economics. Once the Barnett, Fayetteville, Haynesville, and Marcellus plays gained momentum, they decided to hedge their bets by taking positions in new, emerging plays like the Horn River shale in Canada.

Mr. Berman disagreed with the EVA Report's conclusion that production growth is due to the prolific nature of the shale plays because it does not state how many wells are responsible for the production growth, how much gas an average well produces, or how much gas per well is necessary to break even or make a profit. The EVA Report entitled "Changes in the Natural Gas Industry and Its Implications for Energy Projects" refers to well economics. All well economics in the EVA Report use available company information, and Mr. Berman stated that while break-even costs are presented based on what operators present publicly, no details are offered to explain the assumptions, costs, gas price, discount factors, or other data critical to understanding the meaning of these break-even costs. Mr. Berman testified his detailed and ongoing analysis of Barnett, Fayetteville, and Haynesville shale well economics has found operator claims to be consistently overstated by at least 100%. His evaluations of public filings to the SEC further document glaring inconsistencies between the cost information presented in 10-K filings and claims made in company investor presentations, earning calls, and conference calls. Mr. Berman concluded that information regarding reserves and profitability of shale plays provided by companies is often unreliable. According to Mr. Berman, this means the well economics in the EVA Report are similarly unreliable.

Mr. Berman disagreed that the PGC and the EIA have identified increases in shale gas reserves as described in the EVA Report. The PGC and EIA AEO 2011 estimate technically recoverable natural gas resources, not reserves. He stated this is a big difference because resources do not include any economic considerations, but reserves, by definition, must be commercially producible as defined by the SEC. The areal extent of a shale resource indicates nothing about the economics or the potential natural gas production from that resource. In the case of the Barnett, Fayetteville, and Haynesville shale plays, the core areas that have the potential to be commercial now represent 7%–15% of the areas recently claimed by shale

companies to be equally productive and commercial. Mr. Berman stated that even within core areas, commercial production is certain. He said his research does not corroborate shale gas operators' claims that well performance within core areas keeps getting better.

According to Mr. Berman's investigation of the Fayetteville shale, Southwestern Energy, Chesapeake Energy, and Petrohawk Energy have overstated their reserve estimates for the play by 100%. This is largely because they do not follow the best practices for standard decline-curve analyses. Mr. Berman stated it is clear decline rates are far steeper than has been represented, and this is an example of why operator good news must be regarded critically and verified by independent research.

Extensive and expensive improvements in horizontal drilling and hydraulic fracturing have occurred as a result of shale gas plays. Mr. Berman acknowledged that these newer technologies provide better well performance, but he stated it is not clear how lower costs have translated to company profits. The EVA Report's claims of lower costs as a result of these technologies are based exclusively on information from the companies promoting their successes, and he contended such claims are not supported by their SEC filings or balance sheets and are therefore unreliable.

Exploration and production ("E&P") technology advancements described in the EVA Report have contributed to the production from shale gas reservoirs, but the commercial success of shale gas production has not been established to date. Mr. Berman further stated that while there have been technological improvements in shale gas drilling and completion methods, these technologies have a high cost in terms of capital expenditure. Break even NYMEX price justifications for shale gas plays require explanation before they can be realistically evaluated. He stated certain costs such as land, debt service, and overhead are commonly excluded from these analyses.

Mr. Berman also disagreed with the assertion in the EVA Report that natural gas can be produced at costs below \$7 per MMBtu for almost all of the shale plays. The full costs of the shale plays are in excess of \$7.50 per MMBtu on average, and the difference between his numbers and those included in the EVA Report results from the EVA's exclusion of certain costs such as land and debt service. He disagreed with the assessment in the EVA Report that embryonic shale plays could significantly add to shale gas production. According to Mr. Berman, any embryonic and, therefore unproven play, in the oil and gas industry is just an idea and has no tangible value until tested and proved.

The EVA Report indicated that over the next twenty years, shale likely will be the only category of gas to grow because increased shale production will represent the entire growth in the nation's gas production. Mr. Berman indicated he is not in tune with the optimistic tone of this area of the EVA Report and believes the implications of its claims are that there will be serious constraints on natural gas supply in the future. He noted the Powers Energy Investor (April 15, 2011), which states the Barnett and Fayetteville shale plays have peaked and are in decline. Thus, assumed there will be no new major shale plays and concluded this means only the Haynesville and Marcellus shale plays will account for the nation's future natural gas supply. The limits of the Haynesville shale play have emerged (Exhibit AEB-R7), and he believed it is

evident the promise that it will become the largest gas field in North America will not materialize. Further, the Marcellus shale play cannot yet be evaluated since Pennsylvania does not publish monthly production data, but he believed that environmental objections will likely limit the timing and extent of this play's development.

The EVA Report's representations of break even prices for the Marcellus Shale are based solely on shale gas company representations. Therefore, Mr. Berman viewed them as unreliable because there is no way to evaluate assumptions on costs that are included or excluded. Consequently, he also disagreed with the EVA Report's view of break-even prices for the Haynesville, Eagle Ford, Barnett, and Fayetteville shale plays.

Mr. Berman disagreed with the EVA Report's statement that the preponderance of analysis indicates the development of the major shales is commercially viable at gas prices below \$6 per MMBtu and, in most cases, below \$5.50 per MMBtu. He said it conflicts with the \$7.50 MMBtu reference in his pre-filed direct testimony and is at odds with statements by Chesapeake Energy and Chevron Texaco that a minimum of \$6 per mcf is required to justify non-obligation drilling in shale gas plays. Mr. Berman testified it seems unlikely that shale gas production will increase from approximately 20% to 45% of the nation's total natural gas production unless natural gas prices meet at least the \$6 per mcf threshold referenced by Chesapeake Energy and Chevron Texaco. It has taken approximately 25,000 shale gas wells to reach the present level of production, and Mr. Berman stated it would take approximately 30,000 additional wells for shale gas production to reach 45% of the nation's natural gas production, which he referred to as a staggering amount of drilling. This level of shale gas production is inconsistent with the low natural gas prices projected by EVA. Continued low natural gas prices will mean that only obligation drilling will take place, which will not maintain current levels of production.

Mr. Berman also took issue with the assertion in the EVA Report that a \$5.50 per MMBtu price by the end of the year is a highly unlikely possibility. On March 26, 2011, the December 2011 NYMEX price was \$5.10 per MMBtu, or 12% higher than the \$4.56 per MMBtu price quoted in the EVA Report. While NYMEX future prices provide a reasonable calibration for present moment expectations of what investors and gas traders feel about future prices, Mr. Berman stated they are not an accurate mechanism for prediction of natural gas prices more than a few weeks into the future.

The EVA Report's assertion that there has been a fundamental change in natural gas price volatility is another point of contention for Mr. Berman. He stated volatility is the fundamental characteristic of natural gas prices, and this has not and will not likely change substantially in the future. Mr. Berman's interpretation of the PGC's study in 2009 indicated that less than twenty years of natural gas supply exists. He noted this estimate is based on confidence in proved undeveloped reserves. This category of reserves should not be trusted. As the U.S. moves toward greater dependency on natural gas, it seems likely to Mr. Berman the U.S. could find itself strapped for supply despite reserves and resources.

While it may be convenient for companies not to consider sunk costs in forward-looking internal decisions regarding drilling, Mr. Berman disagreed with the EVA Report about this and stated basic economics requires that all costs be included in the full-cycle evaluation. He

believed that for shale gas production, all-in, full-cycle economics are not presented because they are not favorable. He contended debt service should be included in the cost of production. He concluded there is not a profit center for oil and gas companies independent of their oil and gas production that might absorb their interest expense. All costs must ultimately be balanced against the revenue from oil and gas production.

Mr. Berman clarified a statement made in the EVA Report on page 5-9, which said he asserted that E&P requires a payout in two to three years in order to be an economic project. None of his oil and gas clients would invest in a project that did not pay out in two to three years. He stated the implication that shale gas projects require a longer period for payout simply means these projects would not be attractive to most oil and gas clients. He said the fact that shale gas projects are considered attractive even though they do not payout in this timeframe means companies which believe these projects are attractive fall outside the mainstream of the oil and gas investment thinking. He imagined very few private companies are involved in these plays because they must work out of cash flow and must repay debt in the short-term. Only public companies seem capable of defying the fundamental principles that require cash earnings to pay down debt.

According to Mr. Berman, his view of shale gas economics is not very far from the industry consensus. He stated those who say his views are outside the industry consensus are predominantly executives of E&P companies or those who are paid to advance their interests. He stated this group of people do not perform any work of their own as far as technical analysis and therefore has little understanding of the uncertainties surrounding shale gas economics. He said the work of the authors of the EVA Report contains no investigative research or original work, but represents a book report on promotional dogma about the success of shale plays.

Mr. Berman indicated he believes there is a herd mentality regarding shale gas right now. His opinion is that only those who have an integrated perspective on the technical and business aspects of shale plays are in a position to critically determine if the plays make sense; everyone else is in a herd mentality. The technical staff members of E&P companies do not always have the scope to understand the complete picture, are interested in preserving their employment, and do what they are told. The management of E&P companies does no technical work, so he said they do not have any basis to calibrate the facts of a play with its realities. Sell-side analysts who present research on the shale plays must be recognized as having a vested interest to promote the business model of their company to sell stock. Mr. Berman believed these are commonly people without geological, geophysical, or engineering training who do their best to understand and explain data in a business in which they have no direct experience.

While the Barnett Shale may not perfectly represent or predict other shale plays, it is the most complete historical analogue for evaluating shale plays. It provides a benchmark by which we can compare approaches and methods that were either successful or unsuccessful. He added that while other shale plays may be different, they can all be measured in terms of economic variables. When the Fayetteville Shale play emerged, business and scientific people compared it to the Barnett Shale. If it turns out to be different over time, people will adapt their thinking. In regard to the article "How Arthur Berman Could Be Very Wrong," cited by Mr. Thumb, Mr. Berman stated the authors discredited some minor points related to this article published in 2009,

but also agreed with his major points that EUR was over-stated, and group decline methods are largely responsible for this discrepancy.

Finally, with regard to Mr. Stenger's testimony, Mr. Berman agreed with the conclusions in the Bentek report, but failed to see how it supports Mr. Stenger's challenges concerning shale gas viability. The Bentek report concludes that overproduction of gas by the shale companies will challenge the ability of these companies to be profitable. It further notes this overproduction has ruined hedging benefits for the shale gas companies going forward. Mr. Berman stated these conclusions support his belief that shale gas is not commercially viable below \$7.50 per mcf and is unlikely to be profitable until the price meets the marginal cost of production.

I. J. Michael Bodell. J. Michael Bodell is an expert in natural gas fundamentals as they pertain to price formation and price forecasting. Mr. Bodell stated he is familiar with Mr. Berman's analysis of play economics and, on several occasions, he has reviewed Berman's work on play economics for the Fayetteville, Barnett, and Haynesville shale resources. He supported the methodology Mr. Berman used to evaluate shale gas economics, and he employed, on two occasions, an expert reservoir engineer to cross-check Mr. Berman's work. The evaluation of these plays by the reservoir engineer confirmed that Mr. Berman's work is technically sound and accurate. Mr. Bodell agreed with Mr. Berman's conclusions that natural gas operators require at least \$7 per MMBtu to break even in the shale plays, assuming a 10% ROI. Mr. Bodell stated some shale plays, on average, might require a higher market price than \$7 per MMBtu to be economic on an all-in cost basis.

Mr. Bodell testified Mr. Berman has analyzed costs that producers published in presentations, financial statements, and company websites. Mr. Berman has captured the appropriate cost categories and has used costs that are appropriate in today's environment. Mr. Bodell testified that a fully burdened cost structure reflects the full-cycle profitability of the shale gas plays, whereas the point forward costs reflect profitability on a sunk cost basis. Burdened costs include an estimate for drilling, completion and land costs, variable and fixed operating costs, and G&A costs. The point forward sunk cost basis excludes land, fixed operating, G&A costs, and sometimes interest costs for debt. He said burdened costs indicate price points at which companies can enter the business profitably, and the sunk cost basis indicates price points at which continued drilling investment is profitable.

Mr. Bodell testified operators typically evaluate a play on a sunk cost basis, particularly once a firm has invested to secure the land and capital to drill. In some of these shale plays the sunk cost basis alone is on the order of \$6 to \$7 per MMBtu. A well-by-well evaluation is required to fully understand these details, and Mr. Bodell noted this is an important issue because operators will quote their cost performance in public statements but exclude costs essential to understand everything that comprised their unit cost structure. The heart of the issue of unit cost is determining well-level estimated EUR. He stated all-in cost divided by EUR yields a unit cost.

The reason a controversy exists over shale gas economics stems from debate over methodology of decline curve analysis and in creating a type curve for estimating EUR. The EURs, as established by individual well analysis in the Barnett and Fayetteville shales, are substantially lower than previously estimated by operators and other analysts. Mr. Bodell stated

part of the problem lies in how the plant type curve is constructed. Typically, consulting firms that forecast natural gas prices are not willing to evaluate plays well by well because of cost and the belief that a group curve is suitable. However, he said experts in reservoir engineering have shown that group decline analysis overstates EUR. A compounding issue is the development of a type curve with improper b-exponent factors because the use of high factors creates lower annual decline rates and fatter tail-end production, a process that then leads to an overstatement of EUR.

Mr. Bodell testified Mr. Berman has taken the time to evaluate either all or about 90% of the wells in the Barnett and Fayetteville shale plays by vintage to more completely understand their performance. Mr. Bodell said the type of curves Mr. Berman constructed will provide the closest approximation to the EUR. Mr. Berman's assessment of shale plays does not misconstrue either their prolific nature or their economic viability. Mr. Bodell further stated Mr. Berman believes a substantial natural gas resource exists in the nation's shale. However, he stated Mr. Berman believes higher market price levels are required to appropriately reward operators for their development of these challenging resources. He said Mr. Berman's work demonstrates that like conventional gas formations, sweet spots exist within each play that yield the best economics and should be exploited first until prices and technological innovation allow for broader development. In Mr. Bodell's view, Mr. Berman advocates a more measured approach to development, suggesting that in some cases these resources be evaluated in pilot programs. viable.

Mr. Bodell testified Mr. Berman does not have an outlier point of view. Mr. Berman's work on a large number of individual wells shows that early estimates of well EUR are overstated, in most cases by factors of two to three, and this means that the unit all-in cost for shales are underestimated. He noted Mr. Berman concludes that operators are selectively excluding sunk costs to claim that they can make money at prevailing price levels, and significant variability in well performance exists across the resource. Mr. Bodell testified that what Mr. Berman has done with a detailed review of the well data is show that shale plays will not produce as much as previously assumed and that unit cost structure is higher. Mr. Bodell further testified that there are others in the industry, including himself, who agree with Mr. Berman's conclusions. Mr. Bodell supported Mr. Berman's views about future prices, stating that they are likely to be higher and that the trends and variability that have been noted historically will persist.

Mr. Thumb's comments regarding price volatility are somewhat confusing. Mr. Bodell said volatility is highest typically in the late winter in years when storage inventories are the most depleted and a blast of cold weather has threatened supply. High annual variability in price has been noted in historic price spikes that occur when technical volatility was remarkably low. According to Mr. Bodell, the causes of these high spikes are poorly understood by the industry, but can be completely correlated to periods of low storage inventory relative to a volume the market expected.

While it is true that Mr. Berman's material excludes a discussion of the distribution of operator or discreet well performance, Mr. Bodell disagreed Mr. Berman excludes the concept of the marginal producer or the effect of poor producers in his analysis. Mr. Berman has shared with him individual well economics for entire shale plays predicted on well-by-well decline

curve analysis and the distribution of performance within the play. He said Mr. Berman has broken down operator results by portfolio by vintage and plotted the data in histograms to illustrate temporal trends.

The assertion that long-term real gas prices will be below \$7 per MMBtu for the next two decades may be the current consensus view among portions of the industry, but Mr. Bodell stated this does not make it true or an industry-wide consensus. While they are likely to remain below that level for the next several years, he does not believe gas prices will remain below that level for the next twenty years. Conversely, well-known industry consultants Henry Groppe and Charles Maxwell predict prices in excess of \$7 over the next several years. Mr. Bodell stated Mr. Berman's work shows that the cost structure for shale plays is much higher than prevailing market price levels. He said the current shift toward oil drilling is a clear signal that value is not in incremental gas supply, but rather in crude oil.

Mr. Bodell testified there are two major issues that account for the different conclusions drawn by Mr. Bodell and Mr. Berman versus others in the industry regarding shale gas economics. One is the application of reservoir engineering principles, and the second is the distribution of performance within the shale plays as a unit. Mr. Bodell stated the debate concerns factors employed for shale plays, specifically the mathematics of the imperial ARPS equations used in decline curve analysis and to create a type curve for a well. In short, the b-exponent factor used in the exponential form of the equation has a dramatic impact on EUR. He believed use of a b-exponent factor greater than 1.0 is suitable only for transient flow conditions during the initial months after flow begins. Mr. Bodell testified that longer term, such a factor applied to boundary flow conditions significantly overestimates EUR. The shale-dominated companies routinely use b-exponent factors of 1.0 or greater and, according to Mr. Bodell, this leads to two important false conclusions. First, well EURs are two to three times higher than a well will ultimately deliver. Second, unit costs are much lower than actual. Mr. Bodell stated that Mr. Berman has found that group decline analysis performed by operators overestimates EUR and as a result he has conducted these calculations on a well-by-well basis.

The second issue is field extent and uniformity of deposits. Mr. Bodell stated Mr. Berman has demonstrated that well performance in the shale plays is not uniform in geographic extent or over time. Regarding Barnett, he said Mr. Berman's work demonstrates that only a fraction of the play makes economic sense at prevailing prices, and the vast majority of wells will lose money. Mr. Bodell believed the industry is in the process of discovering this as more experience is gained.

Mr. Bodell disagreed the supply curve contained in Exhibit 4-1 in the EVA Report accurately portrays production economics in the natural gas industry. While the general shape of the EVA Report's 2020 cost curve for natural gas is typical, he said the absolute cost levels for segments of supply are too low. Any price plateau will shift upwards by several dollars from that shown in the EVA Report. Further, it will be shorter with a steeper incline in prices toward the most costly terminal supply in the system. He stated gas price projections are almost never robust in nature due to what he called a universe of uncertainty. At the moment, cost escalation for drilling and field services is moving unit costs higher. The most troubling aspect of the EVA Report's forecast is that their price trajectory shows a consistent but small increase in price and

no variability. He said this is in stark contrast to past prices.

Mr. Bodell said natural gas price forecasts have not been able to accurately predict natural gas prices in the past. Unless you have airtight analytics to calibrate all inputs, the output is highly questionable, and such models are very sensitive to the forecast for GDP, which is an input. These models are designed to provide optimized output, which means prices and price variability are always minimized. Because of the degrees of freedom an analyst has over inputs, it is best to characterize output as a scenario rather than a unique solution. Mr. Bodell said he is skeptical that even a group of experts could correctly guess at the thousands of variables and functions needed to preload one of these models to yield an accurate price forecast over a twenty to thirty-year period. Based on his experience, these models cannot capture the full range of circumstances and therefore cannot deliver a reliable long-term price forecast.

Mr. Bodell did not believe that shale gas has improved the ability of forecasters to accurately predict long-term natural gas prices as stated in the EVA Report. Resource cost structure and depletion, natural gas imports and possibly exports, emissions regulations, nuclear plant re-licensing, coal plant retirements, industrial demand, population growth, and U.S. GDP performance, among other factors, will create price variability on the same scale that the markets have witnessed since 2000. These factors will maintain significant uncertainty that will prevent robust long-term natural gas price projections.

Mr. Bodell stated the EIA offers a conventional, if not conservative, view of energy prices. There is no durable conventional wisdom when it comes to price forecasts. When it comes to price formation, particularly long-term price formation, he said there is enormous uncertainty in any estimates. The problem for anyone forecasting prices, he testified, is that there are so many moving parts and, furthermore, few analysts have a complete view of all parts within the system or a cognitive understanding of unintended consequences stemming from change in one sector onto another. He said this is why the EIA gets it wrong and necessitates substantial changes to its twenty-five year view each and every year.

Mr. Bodell testified technical price volatility (annualized percentage of a day-to-day price change function) and medium-term price variability have declined in 2010. Absolute technical volatility achieved a historic minimum in 2010, but the variability of price in 2010 is similar to all other periods except during three notable price spike periods. Technical volatility was actually rather low during these price spikes, which means that as price was moving up and down during the spikes, price evolution was patterned and uniform.

Mr. Bodell disagreed with the statement on page 5-3 of the EVA Report that shales have caused a fundamental change in the volatility in gas prices. The processes that historically have characterized price volatility and variability will operate in the future in the same manner. Supply and consumption will continue to respond to price signals with equal force, and he stated that temporarily, volatility and variability of price have moved to a local minimum. The notion that shale gas is a game-changer is misleading, and Mr. Bodell testified Mr. Berman's research and work that Mr. Bodell has conducted show shale gas economics are highly variable and the spatial distribution of play sweet spots is driven by geology.

Mr. Bodell added the cumulative impact of weather events on storage inventories is more likely to cause higher volatility and variability during periods of tight supply. He further stated this past winter delivered very cold weather to the consuming East and the Producing Region, but maintenance of robust storage inventories from over-development of shale gas nearly matched the increase in weather-dependent consumption. As a result, he testified comparative inventory did not move into severe deficits as in the past, and the market priced gas accordingly.

Mr. Bodell believed the nation will experience periods of tight natural gas supply and volatility in the future. A secular shift is underway in investment away from natural gas because that commodity does not provide the best value proposition. At some point, the bulge in spare productive capacity will decline and the balance between supply and demand will tighten. He stated that high crude oil prices and low natural gas prices are causing a dramatic shift in capital raises among investment banks. In addition, virtually all shale-dominated producers have announced a move toward plays with liquid or oil components because, according to Mr. Bodell, they cannot make money at prevailing prices and higher value exists elsewhere. This shift in investments is clear in U.S. drilling rig commitments and is likely to lower medium-term shale gas supply and tighten supply-demand fundamentals. Mr. Bodell further stated that if this occurs, market prices for natural gas will rise within several years.

Mr. Bodell testified shale plays remove a certain geologic risk because of their extent, but are still subject to economic forces as far as exploitation is concerned. As shale gas plays are exploited, their performance will change and probably decline, based on experience in the Barnett and Fayetteville shales. He said what today is touted as a prolific and reliable source may prove otherwise. Mr. Bodell stated that more recent analysis demonstrates further that reserves in evaluated shale plays are likely to be less than 50% of currently assumed volumes.

Mr. Bodell disputed the statement on page 5-6 of the EVA Report that a gas purchaser could simply hedge equivalent gas lines using the NYMEX future for gas prices. Mr. Bodell stated a gas purchaser can hedge forward, but transaction-wise, the liquid portion of futures is effectively twelve months, with some liquidity out to thirty-six months, depending on the volumes. Putting in place a hedge that would be the same quantity of gas as that sold under the SNG Contract would encounter several obstacles. For example, the firm would need to trade constantly to roll contracts to farther dates to bridge the period in question. Also, he said the mark-to-market risk will require quarterly adjustments to financial statements, which he said is likely to recreate issues with utilities.

Mr. Bodell disagreed with Mr. Norman's assertion that NYMEX futures contracts represent combined expectations of natural gas market participants regarding the future path of natural gas prices. He said NYMEX future prices are not a price forecast, but represent supply and demand for a contract, established by a bid-ask auction mechanism. He stated spot and future prices are also co-integrated. When spot prices move up, future prices tend to move in the same direction, while the size of the price change depends on the date of the contract. He stated NYMEX prices do vary by day, by week, by month, and by year. Mr. Bodell testified the core agenda for the American Clear Skies Foundation is to promote natural gas use over coal in the generation of electricity. Mr. Bodell disagreed with the information presented in the Clear Skies Report. He stated it has been issued without the benefit of detailed analysis of the performance of

shale plays.

13. Commission Discussion and Findings. Joint Petitioners request that the Commission approve the SNG Contract between IG and the IFA; order, if the Commission determines it to be necessary, the Indiana regulated energy utilities to enter into UMAs with the IFA; grant IG the certificate required by Indiana Code § 6-3.1-29-19; and decline to exercise its jurisdiction over IG. The Commission will address each request separately.

A. The SNG Contract. Indiana Code ch. 4-4-11.6 generally concerns the SNG Contract. Under Indiana Code ch. 4-4-11.6, the Legislature provided the Commission a limited role with respect to approval of the SNG Contract. According to Indiana Code § 4-4-11.6-14(b), “The authority shall submit a final purchase contract to the commission for approval.” Purchase contract, or the SNG Contract, is defined by Indiana Code § 4-4-11.6-7 as a contract that

(1) is entered into by the authority and a producer of SNG for the sale and purchase of SNG;

(2) has a thirty (30) year term;

(3) provides a guarantee of savings for retail end use customers; and

(4) contains other terms and conditions determined necessary by the authority.

The dispute raised in this Cause regarding Indiana Code § 4-4-11.6-7 focuses on whether the SNG Contract guarantees savings for retail end use customers.⁸ The parties presented evidence identifying numerous issues that impact whether the SNG Contract will actually save retail end use customers money. These issues are listed and addressed below. The parties agree the SNG Contract entered into by the IFA meets the requirements of Indiana Code § 4-4-11.6-7(1), Indiana Code § 4-4-11.6-7(2), and Indiana Code § 4-4-11.6-7(4), which is supported by the evidence presented.

1. Standard of Review. In addition to the guarantee of savings, the parties debated the standard of review to be employed by the Commission when considering the SNG Contract for approval. The Legislature provided its findings concerning SNG and natural gas supplies, generally, in Indiana Code § 4-4-11.6-12, which states,

(1) The furnishing of reliable supplies of reasonably priced natural gas for sales to retail customers is essential for the well being of the people of Indiana. Natural gas prices are volatile,

⁸ Indiana Code § 4-4-11.6-10 defines retail end use customer as “a customer who acquires energy at retail for the customer’s own consumption: (1) from a gas utility that must apply to the commission under IC 8-1-2-42 for approval of gas cost changes; or (2) under a program approved by the commission through which the customer purchases gas that would be subject to price adjustments under IC 8-1-2-42 if the gas were sold by a gas utility.”

and energy utilities have been unable to mitigate completely the effects of the volatility.

(2) Long-term contracts for the purchase of SNG between the authority and SNG producers will enhance the receipt of federal incentives for the development, construction, and financing of new coal gasification facilities in Indiana.

(3) The authority's participation in and oversight of the purchase, sale, and delivery of SNG to retail end use customers is critical to obtain low cost financing for the construction of new coal gasification facilities.

(4) Obtaining low cost financing for the construction of new coal gasification facilities is necessary to allow retail end use customers to enjoy the benefits of a reliable, reasonably priced, and long-term energy supply.

The Legislature did not include in Indiana Code ch. 4-4-11.6 what must be considered by the Commission when approving the SNG Contract. Moreover, Indiana Code § 4-4-11.6-7 only defines a purchase contract, listing the criteria that must have been included in the SNG Contract to be submitted for Commission approval. The Commission further notes "guarantee of savings" in Indiana Code § 4-4-11.6-7(3) is undefined by the Legislature. The Commission disagrees with Joint Petitioners' assertion that we must approve the SNG Contract if it meets the definition in Indiana Code § 4-4-11.6-7.

In determining whether the SNG Contract satisfies the Legislative intent, the Commission's analysis of the SNG Contract should include, consistent with our duties under Title 8, the impact of the SNG Contract on retail end use customers, and specifically the reasonableness of the price of SNG, the allocation of risk under the Contract, and whether the Contract is in the public interest. Interpreting the SNG Statute to be consistent with our regulatory jurisdiction in Title 8 complies with the principle that statutes relating to the same subject matter should be construed together so as to produce a harmonious statutory scheme. *Sanders v. State*, 466 N.E.2d 424, 428 (Ind. 1984); *Holmes v. Review Bd. of Ind. Empl. Sec. Div.*, 451 N.E.2d 83, 86 (Ind. Ct. App. 1983) (citation omitted); *Sangrilea Boys Fund, Inc. v. State Bd. of Tax Comm'rs*, 686 N.E.2d 954, 958 (Ind. T.C. 1997).

2. Guarantee of Savings. As stated previously, much of the disagreement in this Cause concerns the guarantee of savings required by Indiana Code § 4-4-11.6-7. As a prelude to our discussion and findings on the guarantee of savings, it is important to establish that the guarantee of savings and the savings themselves are different things. The statute does not require a specific amount of savings. Rather, it requires a guarantee of savings.

A reasonable interpretation of Indiana Code § 4-4-11.6-12 is that the Legislature hoped adding the SNG component to the State's natural gas supply would produce savings against the status quo. At the same time, it is obvious the Legislature understood these savings were not certain; otherwise there would be no reason to require a guarantee. Therefore, it is reasonable to conclude that the Legislature fully understood a definitive amount of savings may not be capable of determination; it is possible, even probable, savings would not occur in each and every period of the stipulated thirty-year term; and consumers may or may not realize the savings within the

term of the Contract. The statute requires a guarantee of savings specifically because volatile gas prices and an uncertain future make it impossible to know with certainty that the price of SNG will always be lower than natural gas.

Joint Petitioners assert the SNG Contract provides a guarantee of savings of \$100 million in real dollars for customers, and this guarantee is backed by substantial remedies and collateral, including the SNG Facility, which has a projected appraised value at the end of the term of \$1.8 billion in real dollars and \$4.5 billion in nominal dollars. According to Ms. Alvey, recourse is available to the Authority under the SNG Contract's guarantee provisions to secure the guarantee of savings. If the guarantee of savings is not realized at the end of the initial thirty-year term, IG can pay cash to make up the shortfall. If IG chooses not to pay for the shortfall in cash, the IFA can: (1) extend the term of the SNG Contract for a period of time necessary to remedy the shortfall, or (2) force the sale of the SNG Facility to pay for the shortfall. If the term of the SNG Contract is extended to realize the shortfall, the IFA will purchase the SNG at a discounted price. The discounted price will be based on the actual fixed and variable operating and fuel costs incurred by IG in producing the SNG, including a \$10 million nominal annual operating fee, adjusted annually for inflation (effectively eliminating most of the capital component).

The Six LDCs and Vectren Energy oppose approval of the SNG Contract and assert the SNG Contract does not provide the statutorily required guarantee of savings because (1) consumers may not realize savings during the term of the SNG Contract if market prices are periodically lower than the SNG Contract price or, in the aggregate over the term, if market prices are lower than the SNG Contract price; and (2) the options afforded the Authority for fulfillment of the "promise" of the guarantee at the end of the term are not adequate. Vectren Energy and the Six LDCs argue that these guarantee provisions fall short of the guarantee of savings required by the SNG Statute. In Mr. Ulrey's opinion, the SNG Contract does not provide a guarantee of savings because IG may choose to not pay for the shortfall in cash. Also, there is no guarantee that an extension of the Contract will make up the shortfall or that the market value of the SNG Facility at the end of the initial thirty-year term will be adequate to deliver the guaranteed savings. Mr. Kerney notes the lenders of the SNG Facility's debt capital would have first rights on the proceeds from its sale, if there are any, to meet any mortgage. Therefore, the SNG Contract does not provide a guarantee of savings to customers.

In debating whether a guarantee of savings exists, the parties raised several issues, which relate to the sufficiency of the guarantee. The Commission will address each issue separately.

a. Value of SNG Facility at the End of Term. An important part of the collateral package referenced in the previous section concerning the guarantee of savings is the value of the SNG Facility at the end of the thirty-year term of the SNG Contract. Joint Petitioners provide a detailed appraisal concerning the SNG Facility's value. Specifically, Kevin Reilly, who is employed by American Appraisal Associates, testified on behalf of Joint Petitioners. American Appraisal Associates has extensive experience appraising power plants, oil refineries, petrochemical plants, pipelines, and general manufacturing facilities.

Mr. Reilly testifies that he considered three traditional approaches for valuation: sales comparison, income, and cost approaches. Because of the new and complex nature of the coal

gasification market, there are no current or anticipated future transactions from which the sales comparison approach would provide a meaningful measure of future value. Therefore, the sales comparison approach was not used in the appraisal. He states the detailed analysis under each of the two remaining approaches results in significant value to the SNG Facility for the year 2046. Mr. Reilly uses common appraisal procedures and techniques to appraise the SNG Facility. The following were analyzed to conduct the appraisal:

- The area and surrounding neighborhoods,
- History and nature of the business/industry,
- Extent, character, and utility of the property,
- Continued use of the property at the proposed location,
- Highest and best use of the property,
- Estimated replacement cost new less an allowance for depreciation or loss of value, arising from condition, utility, age, wear and tear, and obsolescence,
- Capacity of property,
- Actual production levels and effect of supply and demand on future operations,
- Forecast revenues, operating expenses, and expenses due to capital expenditures,
- General economic trends and specific economic influences affecting the operations under review, and
- Comparable property sales.

The first appraisal method Mr. Reilly uses is the discounted cash flow income method. According to Mr. Reilly, this method determines a future value over the life of the SNG Facility through the projected present cash inflows and outflows. For the SNG Facility, Mr. Reilly states cash inflows or revenues would include income from the sale of SNG, market power, CO₂, argon, sulfuric acid, and rare gases. Cash outflows or expenses would consist of operating expenses, future capital expenditures for replacement to support or maintain current operations, and any required additions to working capital necessary to support growth and sales revenue.

In order to calculate the present value of projected debt free cash flows of a project, an appropriate discount rate or WACC must be determined, and Mr. Reilly uses 8.5%. He adjusts the after tax discount rate of 8.5% to a pre-tax WACC of 14.3%. He then discounts cash flows over a six-year projection period, and for the subsequent periods, the projected income after deductions is capitalized by a direct capitalization rate then reduced to present value. He also includes the costs associated with the operations and maintenance and fuel, which are inflated for the final year's price by an inflation rate of 2.5% annually.

Mr. Reilly also explains that the indicated value of the SNG Facility as a viable operating entity into the future is equal to the sum of the present values of the interim projections of income after deductions, plus capitalization of the projected future profit, also discounted to present value. As a result of his analysis, he states the business enterprise value for the SNG Facility based on the income approach is \$4,910,496,000.

The second appraisal method Mr. Reilly uses, the cost approach, appraises assets through the estimated cost a buyer would pay to purchase a replica of the SNG Facility. The SNG Facility has not been constructed; therefore, Mr. Reilly uses the cost to construct it as the cost to

build a replacement. Since this appraisal method determines the SNG Facility's physical condition as of June 30, 2046, the physical deterioration is based on an age/life relationship, estimates of effective age, and remaining useful life.

Because coal gasification is a relatively new technology, Mr. Reilly acknowledges it is difficult to predict what the functional obsolescence will be at the end of thirty years. However, he looks at past history of the chemical process industry to predict the advances that will occur over the thirty-year period. He estimates the functional obsolescence penalty as of June 30, 2046 at 10%. For the purpose of the appraisal using the cost approach, Mr. Reilly determines the value of the working capital to be 10% of projected revenues, or approximately \$1.3 billion. Intangible assets fall within a range of 5% to 10% of the business value. The cost to purchase approximately 1,300 acres of land as of June 30, 2046 is calculated by applying a 2.5% annual inflationary rate of the current cost of \$21.9 million, resulting in \$56.6 million.

All elements of the cost approach—cost of replacement, physical deterioration, functional obsolescence, and economic obsolescence—are considered and quantified by Mr. Reilly. He testifies the business enterprise value for the SNG Facility is \$4,178,700,000 in 2046 dollars. He also indicates coal gasification technology provides functional flexibility that enhances the economic viability of the project because operational and strategic decisions can be made about fuel feedstock and product output to maximize the value of the SNG Facility and minimize any economic obsolescence.

When the value of the income approach of \$4,910,496,000 is averaged with the value of the cost approach, the appraised value of the SNG Facility is \$4,545,000,000 at the end of the thirty-year SNG Contract term, or \$1,778,000,000 in 2008 real dollars.

With respect to the value of the SNG Facility, Vectren Energy's witness Mr. Ulrey states that in his opinion, there is no guarantee a sale of the SNG Facility will produce adequate revenues to cover any savings shortfall. However, as Ms. Alvey points out, the analysis provided by Vectren Energy and the Six LDCs concerning the SNG Contract indicates that ratepayers will experience losses at the end of the thirty-year term, which are significantly less than the appraised value of the SNG Facility. For example, Mr. Norman's worst case scenario provided in Exhibits RN-8 and RN-10 show losses to incurred in the amount of \$1.597 billion, while Mr. Reilly appraises the value of the SNG Facility at approximately \$4.6 billion.

The Commission also notes Joint Petitioners were the only party to provide an appraised value of the SNG Facility. Further, nothing in the record exists indicating Mr. Reilly's appraisal methods, inputs used, and ultimate value of the SNG Facility are unreasonable. Even if at the end of the thirty-year term of the Contract ratepayers experience \$1.6 billion in losses as indicated by Vectren Energy's witness Mr. Norman, the appraised value of the SNG Facility significantly exceeds such losses.

Accordingly, based on the evidence provided by Mr. Reilly, we find that \$4,545,000,000 in 2046 nominal dollars, which according to Mr. Reilly equates to approximately \$1.8 billion in 2008 dollars, is a reasonable estimate of the future value of the SNG Facility and provides support that a guarantee of savings exists.

b. Natural Gas Price Uncertainty. A substantial body of evidence has been presented in this Cause regarding short- and long-term views of future natural gas prices, various long-term natural gas price forecasts, and the implications of expanding shale gas production on natural gas prices. The evidence shows fundamental disagreements among expert witnesses regarding future natural gas prices, price drivers, and the appropriateness and accuracy of different long-term natural gas price forecasts. Generally, the divergent views grow out of disagreements about the most appropriate forecasting assumptions and models to employ, with much of the disagreement focused on assumptions or scenarios concerning the future implications of shale gas production and production costs for U.S. natural gas markets. Conflicting evidence was presented concerning the advent of shale gas and whether it has fundamentally changed U.S. natural gas markets and pricing expectations. According to evidence presented by the Joint Petitioners, shale gas economics remain uncertain, do not necessarily support low price expectations in the future, and have cost realities for commercial production, which are just now beginning to be understood.

According to the evidence presented by the Joint Petitioners, the most widely-known forecast of long-term gas prices is produced by the EIA, which is inherently inaccurate with respect to the timeframe of the applicable data and has a historic record of predicting lower than actual natural gas prices.⁹ Thus, Joint Petitioners used a composite of natural gas forecasts. Joint Petitioners base forecast falls below a regression line that is based on historical pricing projected forward as depicted on Exhibit JMA-7.

The evidence presented by Joint Petitioners also indicates that the natural gas market and the price of natural gas are volatile. Further, natural gas price forecasting is uncertain and has limitations. Joint Petitioners' evidence indicates there is a substantial risk that the supply and extraction assumptions for shale gas have been exaggerated, and the unit cost of extraction has been underestimated. Shale gas resource size has been shown to be a poor method of estimating commercial reserves, and the commercial realities do not support the levels of production or profitability from shale resources that many are predicting. There are significant costs associated with shale gas production that call into question its economic viability, when considering land acquisition, debt service, general and administrative expenses, dry hole costs and plugging, and abandonment expenditures. Further, as Mr. Maley points out, environmental concerns create risk, uncertainty, and ultimately increases the cost associated with shale gas production. Technological advancements related to shale gas have also contributed to the cost of production.

Mr. Maley explains that fundamentally, the SNG Contract is about the uncertainty of natural gas. He states Joint Petitioners have demonstrated there is considerable uncertainty in the future price of natural gas, prices are volatile and will remain volatile in the future, and natural gas price forecasts are unreliable due to inaccurate assumptions and unpredictable events that are

⁹ Ms. Alvey explains that according to EIA's self-evaluation data and going back fifteen years using EIA gas price forecasts from 1996 to the 2009, the EIA forecast of the prices would be lower than actual. She points out the EIA only missed on the high side 8% of the time. She also states the magnitude of the EIA miscalculation was large and heavily skewed to the downside miscalculations. She explains, when the actual price of gas turned out to be higher than the EIA forecast, it averaged 43% higher than forecasted, and when the actual price of gas was lower than forecast, it averaged 6% lower. The historic EIA forecast error was demonstrated on Exhibit JMA-6.

not included in the models. Mr. Maley further states that shifting a portion of the gas paid for by consumers away from the unpredictable natural gas market prices to a formula-based price which has a fixed capital component, an O&M component that moves with inflation, and a variable component based on coal is a sound beneficial diversification of supply.

Conversely, Vectren Energy's witness Mr. Thumb states shale gas will be a dominant source of new production over the next two decades and will represent approximately 45% of domestic U.S. production in the years to come. He believes shale gas can be developed at prices below \$6.00 per MMBTU. Mr. Thumb's Exhibit 2-7¹⁰ illustrates two large producers in the Marcellus shale play, the decline in costs to drill, and the increase in estimated ultimate recoveries over the past three years. In addition, he states there are numerous shale plays that are still in the infantile stage and could ultimately become major contributors to U.S. production. Current price and supply forecasts do not consider these emerging shale plays in their analyses. Furthermore, Mr. Thumb states, the majority of gas price forecasts predict prices well below Joint Petitioners' \$7.00/MMBtu estimate for roughly the next two decades. In Mr. Thumb's opinion, Mr. Berman's price forecasts for 2011 and 2012 are far from the industry consensus.

Six LDCs witness Mr. Stenger agrees with Joint Petitioners that natural gas prices are volatile. He also states all energy commodity prices are volatile, and the pricing projections used by Joint Petitioners ignore the historic relationship between the prices of natural gas and coal. The price the IFA has agreed to pay for SNG manufactured by IG is dependent on the price of coal. The disregard of the relationship between natural gas and coal makes it difficult to predict future prices for these commodities because the further out in time the prediction, the less reliable the prediction. Mr. Stenger explains Joint Petitioners are singling out the volatility in commodity pricing for a single year, 2008, as their basis for the approval of the SNG Contract even though the price of coal was more volatile than the price of natural gas during the July 2007 through July 2008 period. Any volatility in the coal market could lead to the price of SNG being higher than the price of natural gas, negating one of the stated benefits of the SNG project.

The Office of Utility Consumer Counselor (OUCC) witness Mr. Miller's cross answering testimony summarizes the variety of opinions about the future of natural gas prices. He explains:

Each of these parties (Vectren, Citizens Groups and Six LDCs) claims that [IG's] base case forecast of natural gas prices is far too high. Each party presents an alternative natural gas price forecast and uses that alternative forecast to determine the likely net benefits (or net losses) to Indiana customers from the proposed SNG Contract. Each party's witnesses conclude that the SNG Contract is likely to result in losses for Indiana customers, and each party's witnesses recommend that the Commission should not approve the SNG Contract. For each party, the results of the benefits analysis based on alternative natural gas price projections are a major part of the reason for recommending rejection of the SNG Contract. . . . It is not important for the Commission to determine which natural gas

¹⁰ Exhibit 2-7 illustrates a roughly 60%–70% decrease in drilling costs and an approximate 36% increase in estimated ultimate recovery per well.

price forecast is “best” or most likely. The Commission should instead try to identify a range within which future gas prices are likely to occur. . . . The Commission can then make judgments about the likely range of possible net benefits or net losses to Indiana customers from the SNG Contract, and it can assess the likelihood of various possible levels of net benefits or net losses.

Public’s Exhibit 2-CA at 1–3. In Mr. Miller’s opinion, the IG Base Case falls with a range of reasonableness concerning the likely future prices of natural gas.

Based on the evidence presented, we find there is only one clear and undisputable conclusion that can be reached, which is that there is considerable uncertainty with future natural gas supply and prices, and gas prices are volatile and unpredictable. Even natural gas experts have diametrically opposed views on future market and pricing expectations. The SNG Contract must be considered in light of this undeniable uncertainty.

Fundamentally, the Commission views price uncertainty as supporting the case for supply portfolio diversification. The legislative findings in Indiana Code § 4-4-11.6-12 indicate that the Legislature reached the same conclusion. The SNG Contract will help diversify consumers’ natural gas risks for a portion of the gas they consume. While the SNG Contract is not a hedge, it compliments existing, shorter-term hedging programs currently employed by Indiana utilities at the direction of the Commission. The SNG Contract will help to reduce variability and provide protection against high natural gas prices and unexpected price increases when consumers are most at risk for a small but significant part of their gas cost exposure.

The evidence presented did not indicate that Joint Petitioners’ natural gas forecast is outside of the reasonable price range. Rather, as stated above, the evidence concerning future natural gas prices indicates a high degree of uncertainty, unpredictability, and volatility, which affirms a fundamental benefit of the SNG Contract. When the SNG Contract is viewed in light of the Legislative intent in Indiana Code § 4-4-11.6-12, the unpredictable and volatile nature of natural gas prices, and the lack of evidence indicating Joint Petitioners’ forecast is unreasonable, the Commission finds Joint Petitioners forecast to be within a reasonable range and provides a sufficient demonstration that a guarantee of savings exists.

c. Coal and Petroleum Coke Procurement and Pricing.

The SNG Contract will diversify gas customer fuel purchases by substituting coal for gas. Joint Petitioners assert that coal prices are less volatile than gas prices. Therefore, Joint Petitioners believe this substitution responds to the Legislature’s findings that gas prices are volatile and construction of coal gasification facilities with low-cost financing should allow customers to enjoy reasonably priced energy.

Similar to the disagreement of the parties related to the impact of shale gas production on future gas price levels and volatility, the parties also debated whether future Illinois Basin coal prices would necessarily be more stable than gas prices. Joint Petitioners explain that through the use of ladder coal contracts with staggered expiration dates, changes in coal spot market prices, which have been more volatile of late, could be muted. Even so, the assertion that Illinois

Basin coal prices will be favorable over the thirty-year contract period as compared to gas prices is a separate issue. Both Vectren Energy witness Ms. Medine and OUCC witness Mr. Bolinger agree there are a number of cost factors that could likely continue to put upward pressure on future Illinois Basin coal prices, including increased demand resulting from global and domestic demand for Illinois Basin coal due to the installation of scrubbers on Eastern U.S. power plants. Tr. at I-67, I-70.

Joint Petitioners also argue that the ability to, at times, use some petcoke instead of coal could also help to reduce costs. Ms. Medine, Mr. Maley, and Mr. Weiss disagree on whether petcoke prices, like coal, would be driven by global demand, or would be more regionally based. According to Joint Petitioners, petcoke will be an “opportunity fuel” that could be purchased at times if it is cheaper than coal.

Having considered the evidence presented in this Cause, we find IG has a reasonable fuel procurement strategy that, in accordance with the SNG Contract, must employ a laddered contract approach consistent with the approaches of large coal purchasers. The Commission finds the SNG Facility’s location on the Ohio River, with the ability to receive coal from a barge, rail, and truck, is advantageous for assuring long-term coal supply reliability and competitive pricing.

The evidence also supports the view that the pricing IG is likely to experience for its coal and petroleum coke fuel supplies should be less volatile than natural gas prices. A fundamental difference between these energy commodities—natural gas on the one hand and coal on the other hand—is how they are typically purchased by energy users in the marketplace. Credible testimony from Mr. Weiss and Mr. Maley indicates that only about 7% of the coal purchased in Indiana and across the U.S. is on the spot market. The evidence also indicates that Indiana electric utilities procuring coal through laddered bilateral contracts have not seen significant price volatility. There is no evidence to suggest that IG, following a laddered contracting strategy similar to most Indiana coal-based utilities, will see greater coal price volatility than the historic patterns for these Indiana coal utilities. Even if IG experiences variability in its fuel prices similar to that seen historically by Indiana coal utilities, the impact on the SNG price variability should be minimal and less than the variability that has been experienced in natural gas prices.

The Commission is also persuaded by the evidence that petroleum coke may be utilized when petroleum coke prices are low relative to coal prices. Fuel flexibility is an important feature of the gasification technology used at the SNG Facility. While the evidence indicates petroleum coke prices can be subject to variability, the evidence also shows that the variability of Midwest petroleum coke prices is typically less than the variability of petroleum coke pricing on the Gulf Coast. Consequently, we find it inappropriate to consider the SNG Project as a 100% coal-fired facility for evaluation purposes. The option for IG to blend petroleum coke, and for the Authority to have input concerning whether more than 15% petroleum coke is utilized, provides an additional fuel supply option and diversification that will be beneficial for Indiana gas consumers purchasing SNG. The evidence does not show a strong correlation between the average monthly prices paid by Indiana utilities for coal and monthly prices paid for natural gas, further supporting our finding that the SNG Contract will help diversify Indiana consumers’ gas price portfolio while providing a guarantee of savings.

d. Consumer Savings. The SNG Contract includes mechanisms for ongoing calculations of consumer savings during its term and for maintaining an account to track cumulative or aggregate consumer savings over its term. The savings calculations are based on comparing average monthly natural gas market prices realized for sales of SNG against the SNG “Adjusted Base Contract Price” for the same month, taking into account any use of the CPR. This Market Differential calculation determines whether consumers have saved money and will receive a credit on their bills from the SNG, or whether the SNG has cost more than market natural gas and will result in an additional charge added to their bill for the month. These Market Differentials are aggregated during the thirty-year term in the savings tracking account, which is used to determine the cumulative savings (or cost) that has been realized by the end of the SNG Contract term.

The Commission first notes the SNG Statute does not provide a definition of savings. The SNG Contract defines savings as a function of the difference between the formula price of SNG and the market price of SNG. Under the proposed Contract, the Market Differential net of any application of the CPR would be the savings.

Considerable evidence has been presented in this Cause regarding modeling analysis to evaluate consumer savings over the term. Savings estimates presented a range from well over \$1 billion of net savings to consumers to costs of well over \$1 billion to consumers. It is clear from the evidence presented that the underlying modeling assumptions and scenario inputs regarding natural gas prices, and to a lesser degree coal and petroleum coke prices, are major drivers of the Market Differential calculations and modeling results presented by the parties. Depending largely on what future commodity price assumptions are incorporated into the models, the various analyses either demonstrate considerable positive Market Differential and savings, considerable negative Market Differential and costs, or something in between. It is also clear that different modeling and analysis techniques can be employed to evaluate outcomes, producing different results, and the expert opinions concerning the appropriateness of different techniques are divided.

Ms. Alvey provides a way to calculate consumer savings as depicted by Exhibit JMA-8. She calculates the financial impact of the SNG Contract on a total gas bill for the average residential gas consumer. To do this, Ms. Alvey presents a Base Case based on the forecast formula price of SNG and the Authority’s consensus forecast of market price for natural gas. Also presented are two extremes in the Authority’s sensitivity analysis varying the two most influential variables in the analysis, market gas prices and market coal prices, which produce a Highest Savings Case and a Lowest Savings Case.

In the Base Case the SNG Contract is forecast to save 1% of what consumers would otherwise pay for gas in the status quo. The Highest Savings Case shows that consumers would save about 3% on their bills with the SNG Contract versus the status quo, while the Lowest Savings Case shows that the SNG contract would cause consumers to pay 7% more for their gas versus the status quo. Each of these scenarios calculates projected savings based on the SNG Contract definition of savings.

Ms. Alvey indicates that by utilizing the Authority's Base Case composite natural gas price forecast, together with EIA's coal price forecast and the petcoke price forecast from Jacobs with an assumed 15% petcoke blending, the Authority expects \$500 million of "real" savings in 2008 dollars for Indiana gas customers over the term of the SNG Contract, and nearly \$1.2 billion in nominal dollars over the term of the SNG Contract.

Vectren Energy witness Mr. Norman, Citizens' witness Mr. McCullough, and the Six LDCs' witness Mr. Stenger disagree with Joint Petitioners' analysis of the potential benefits to Indiana consumers from the SNG Contract. As discussed above, each use differing inputs into models, which result in different outcomes. Mr. Norman, Mr. McCullough, and Mr. Stenger conclude consumers would not experience savings, and therefore the SNG Contract should not be approved.

On rebuttal, Mr. Hanser testifies that although both Mr. McCullough and Mr. Norman purport to present their modeling analyses as sophisticated financial analyses, these analyses are technically and conceptually flawed. As a result, they provide neither a reasonable nor a reliable assessment of the value of the SNG Contract to Indiana consumers. Mr. Maley agrees that the modeling results presented by Mr. Norman are strictly a function of incorrect modeling assumptions, including assumptions about the use of petcoke, inflation rate, and the EVA Natural Gas Price Forecast.

Having considered the evidence presented regarding modeling analyses and other estimates of consumer savings under the SNG Contract, we cannot conclude that the SNG Contract will provide a specific amount of consumer savings under the SNG Contract because savings will be highly dependent on future commodity prices, particularly natural gas prices, and to a lesser degree coal and petroleum coke prices. The evidence demonstrates strong disagreements about the most appropriate modeling techniques to evaluate these consumer savings and what errors or flaws may exist in various modeling approaches presented. While estimates of potential consumer monetary savings scenarios are important and provide important information for the Commission to consider, the evidence indicates that future commodity price uncertainty, particularly over the long term, renders modeling and other calculations of consumer savings imprecise at best and potentially misleading at worst.

However, sufficient evidence exists for us to find that the model and inputs used by Joint Petitioners to calculate consumer savings under the SNG Contract to be reasonable. While the actual amount of savings cannot be predicted with certainty, the Commission notes alternative provisions are present in the SNG Contract to provide the guarantee of savings. Specifically, at the end of the thirty-year term, IG may pay in cash any shortfall that may exist, the SNG Facility may be sold and the proceeds used to pay any savings deficit, or the Contract term may be extended at a lower SNG price until savings are achieved.

e. **Intergenerational Implications.** Intergenerational equity is an issue that exists in all cases involving long-lived assets, even if not an issue in dispute in those cases. During cross-examination, Ms. Alvey testified that concerns about intergenerational effects relative to the SNG Contract are partially addressed by the benefits that can accrue to the children or grandchildren of an older individual who does not live to see benefits late in the SNG

Contract or from the guarantee after the term. Ms. Alvey also testifies that the Authority considered the intergenerational issue in terms of all retail end use customers versus a single individual.

Mr. Shambo testifies that a type of intergenerational equity should be considered with respect to the UMA. His concern touches on a different aspect of intergenerational equity. He cautions that customers who could qualify to be exempt from the SNG Contract should not be able to opt in and out based on the then-current economics of the transaction.

It is not clear today, despite the analysis presented in the Cause, when benefits or costs may be incurred by consumers from the SNG Contract since natural gas price variability is likely to determine the timing of actual savings and costs. It could be the case that natural gas prices rise sharply by 2015 and significant benefits from the SNG Contract are realized in the early years, or it could conceivably be that the benefits are only realized through the guarantee after the end of the term.

We presume that these intergenerational implications were considered by the Legislature when it required a thirty-year term for the SNG Contract. Further, it is apparent that Joint Petitioners contemplated the issue of intergenerational inequities and attempted to address it the SNG Contract, with the addition of the \$150 million CPR. This account is designed to assuage and balance any losses experienced over time and thus between generations of ratepayers.

While potential intergenerational implications are important, the fact that they exist is not a rationale for abandoning the development of long-lived assets expected to benefit Indiana consumers. The SNG Contract will benefit Indiana consumers on the whole through expected savings during the term, a guarantee of aggregate savings at the end of the term, and diversification of supply to reduce volatility and risk from the first day of the term. While the results realized by individuals who participate in the SNG Contract over periods of time may differ, nothing is inherently inequitable about the SNG Contract or how its benefits may be spread over time.

f. Risk Allocation. The Commission notes that an initial review of the evidence indicates the risk allocation in the SNG Contract is not symmetrical. For example, IG Exhibit DWM-6 shows that if the market price of natural gas is \$2 per MMBtu higher than in IG's Base Case, customers pay 89¢ per unit more for SNG. However, if the market price of natural gas is \$2 per MMBtu lower than in IG's Base Case, the SNG price only goes down by 33¢ per unit. This disproportionate allocation of down side risk to customers results from the fact that the Contract provides the customers will get 50% of profits on the sale of SNG but will absorb 100% of losses on the sale of SNG.

This lack of symmetry is also demonstrated by Vectren Energy Exhibit RN-2, which shows the gains and losses to customers if the market price of gas is \$2.00, \$3.00, and \$4.00 per unit above and below the SNG price. In each case, the losses to customers when the price of SNG is higher than the market price of natural gas are significantly greater than the profits to customers when the price of SNG is lower than the market price of natural gas by the same differential. Consequently, as shown by Mr. Norman, if future gas prices are evenly balanced

above and below the SNG price, customers will still end up with negative savings (losses) under the SNG Contract.

In a similar vein, Section 5.4(c) of the Contract provides that profits on the sale of CO₂ will be shared equally between the customers and IG, but losses on the sale of CO₂ will be allocated 100% to customers. Risk asymmetry also can be seen by comparing the financial results for IG's shareholders and the profits or losses to customers under IG's Base Case, High Case, and Low Case. Vectren Energy Ex. CX-3 (Confidential).

Even though the risk allocation is not symmetrical, this asymmetry does not affect the \$100 million guarantee of savings to be experienced by ratepayers. Losses and gains will still be tracked by the CPR. IG will also place \$150 million in the CPR to cushion the effect of losses experienced over the term of the SNG Contract. If at the end of the thirty-year term \$100 million in savings is not realized, IG will account for any shortfall through one of three methods described previously. Also, as OUCC witness Mr. Miller points out, IG primarily bears the risk concerning the cost of constructing the SNG Facility.

g. Compatibility with Existing Hedging Programs. The Commission has required Indiana LDCs to develop and implement natural gas price hedging programs, and the LDCs have adopted hedging practices to help reduce price volatility. Despite these existing programs, Indiana Code § 4-4-11.6-12(1) states that "[n]atural gas prices are volatile, and energy utilities have been unable to mitigate completely the effects of the volatility." The evidence in this Cause describes some of these existing hedging practices employed by Indiana LDCs, offers different perspectives on the hedging benefits of the SNG Contract, and includes opinions regarding the SNG Contract's compatibility with existing hedging programs.

Mr. Maley describes the SNG Contract as a physical hedge since the SNG Facility is producing the gas to support the purchase agreement. Mr. Maley says there is no evidence that price variability would be the same or greater under the SNG Contract than in natural gas markets. Mr. Shambo, testifying on behalf of NIPSCO, agrees with Mr. Maley's characterization that SNG represents a hedge, but indicates it is primarily a financial hedge in structure. According to OUCC witness Mr. Miller, the uncertainty about the eventual amount of gains or losses experienced as a result of the SNG Contract is the essence of the hedge and not something that detracts from the purpose of a hedge.

Industrial Group witness Mr. Marz testifies that the SNG Contract does not qualify as a hedge because it does not fix the price or limit price risk for any time period. Vectren Energy witness Mr. Norman also states the SNG Contract is not an effective hedge because the SNG cost fluctuates based on changes in the price of coal and other variable inputs; hedges fix a price, providing a known price cap. Further, Vectren Energy witness Mr. Ulrey testifies the SNG Contract may interfere with utilities' efforts to engage in long-term gas supply hedging, which uses lower priced natural gas supplies. He also states the SNG Contract replaces the volatility of natural gas with the volatility of coal and adds risk related to possible CO₂ regulation. Further, the SNG Contract does not cap the potential increases in future natural gas prices since the SNG price is unknown and may be above future market prices.

Based on the evidence presented regarding hedging, the Commission finds the SNG Contract is compatible with, and can be complimentary to, existing hedging programs. The SNG Facility and the SNG Contract provide long-term natural gas supply diversification through a long-term contract with fixed and variable price components and coal-based cost components that will complement the existing hedging programs employed by Indiana utilities. The SNG Contract will not interfere with utilities' ability to hedge their natural gas supply because the regulated natural gas distribution companies are not purchasing the SNG from IG; rather, the Authority is the purchaser of the gas. The regulated natural gas utilities are simply passing through to ratepayers debits and credits related to the utilities' market share of SNG sales. The pass through of debits and credits will not affect the regulated gas utilities' ability to purchase natural gas supply for hedging purposes.

h. CO₂ Risk and Mitigation. The evidence in this Cause includes differing perspectives on potential economic risk to consumers under the SNG Contract resulting from possible future regulation of CO₂ emissions. Joint Petitioners state the SNG Facility is being designed to use advanced technologies to capture 90% of the CO₂ emissions from the gasification process and compress the CO₂ into a liquid form to sell to Denbury Resources for use in EOR operations on the Gulf Coast. This CO₂ transaction will require construction of a CO₂ pipeline, the Midwest Pipeline, to transport the CO₂ from Rockport to Denbury's existing pipeline infrastructure in Mississippi. Joint Petitioners assert this arrangement positions the SNG Project to be held harmless or potentially benefit from future CO₂ regulation since the SNG Facility will already be controlling CO₂ emissions to a level well beyond what can be achieved by conventional fossil fuel technologies.

More specifically, Mr. Hezir states federal regulation that places a price on CO₂ emissions, directly or indirectly, would increase the price of natural gas significantly. He testifies that such regulation would make the price of SNG more attractive than natural gas because the cost of CO₂ capture would have already been included in the cost of production of the SNG. Mr. Maley agrees with Mr. Hezir and asserts the CO₂ risks of the SNG Contract are different than the CO₂ risks now facing natural gas consumers, which is another reason why the SNG Contract is a good diversification tool. According to Mr. Maley, the air permit as filed with the federal government on April 20, 2011 will have no cost impact for SNG consumers, and compliance with the air permit will effectively mitigate CO₂ risk to end-use customers.

Vectren Energy and the Six LDCs argue the use of carbon intensive coal and petroleum coke fuels create additional economic risk from possible future CO₂ regulation for retail end use customers. Further, it is not assured that the Midwest Pipeline will be built and therefore the CO₂ emissions and economic risks from CO₂ emissions associated with the SNG Facility will be similar to traditional coal technologies. Vectren Energy's witness Ms. Retherford recommends that the Commission require assurances from IG that the pipeline will be built as part of any approval of the SNG Contract.

Witnesses from groups opposing the Commission's approval of the SNG Contract also question Joint Petitioners' view of CO₂ regulatory risk and challenge whether the Midwest Pipeline would be built. Mr. McCullough testifies recent setbacks for other Midwest projects that

were potential additional suppliers of CO₂ for the Midwest Pipeline raise questions about whether Denbury will complete it. Although he testifies the defeat of legislation supported by Denbury in Indiana to provide eminent domain for pipeline construction is further evidence Denbury may not build the Midwest Pipeline, the Commission notes that legislation to facilitate the Midwest Pipeline was subsequently passed.

Ms. Retherford and Mr. Ulrey testify the SNG Project produces significant amounts of CO₂, future CO₂ regulations and/or taxes continue to be considered by Congress, and therefore the risk of significant costs related to CO₂ mitigation must be taken into consideration. Ms. Retherford testifies Indiana gas customers could end up paying the tax attributable to the 5.5 million tons of CO₂ expected to be produced by the SNG Facility each year. Mr. Ulrey acknowledges that an effort has been made in the SNG Contract to mitigate CO₂ risk, but he states great uncertainties continue to exist regarding future CO₂ regulations or taxes during the term. Additional CO₂ costs will have a significant negative impact on the SNG Contract outcome for consumers, and if the contingent CO₂ arrangements do not come to fruition, consumers will be at risk for significant additional costs. Mr. Ulrey opines that based on the CO₂ risks/uncertainty, the SNG Contract is too risky to execute at this time.

The Commission agrees with the view shared by all sides in this Cause that the future regulatory path regarding carbon emissions is highly uncertain. Recent economic events seem to have dampened the momentum for federal legislation, but we cannot predict when or if such legislation may regain traction in the future. The EPA has promulgated new rules that require new CO₂ emissions sources to complete CO₂ BACT analyses as part of their preconstruction air permits. IG has filed such a permit and testifies that the filed permit will essentially require a minimum 80% reduction in CO₂ emissions and will not increase costs to retail customers.

CO₂ regulatory risk is an important consideration in evaluating the benefits of any new energy technology, particularly fossil fuel energy technologies. We agree with Joint Petitioners, however, that the SNG Facility represents technology that is well positioned to avoid cost increases and potentially benefit consumers if new CO₂ regulations are implemented in the future. The technology is certainly better positioned than the existing stock of coal power plants that face substantial cost hurdles to capture CO₂ emissions, a challenge SNG facilities address.

Nonetheless, CO₂ regulatory uncertainty is such that it is not possible to be certain what the economic implications might be for the SNG Project, retail end use gas customers in the absence of the SNG Contract, or other users of fossil fuel in the economy. Retail end use customers have CO₂ regulatory cost risk today and will continue to have it in the future with or without the SNG Contract. The implementation of a federal CO₂ regulatory program could easily increase demand and prices for natural gas and/or increase the cost of producing natural gas from shale or other resources. A future CO₂ regulatory program could even directly tax the use of carbon fuel by all users, including natural gas retail end use customers.

Similarly, the SNG Contract carries with it risks that costs could be increased under a CO₂ regulatory program. However, the SNG Contract provides protections to limit this cost exposure under most circumstances. These protections surpass protections energy customers are normally afforded because retail end use natural gas customers currently have no protections

from potential cost increases from CO₂ regulatory changes. Specifically, the SNG Contract caps consumers' exposure to Changes in Government Requirements that impose new CO₂ costs to a 13.5% increase in the then current SNG price. While this would represent a significant increase in price, it also provides a firm price increase cap. Retail end use customers currently do not have any cap on the natural gas price increase they could incur under a CO₂ regulatory program, which, as suggested by the evidence in this Cause, could be much larger than any SNG price increase. The SNG Contract also requires that IG pursue "Commercially Reasonable Efforts" to mitigate any cost increases to consumers. This phrase represents a standard legal term-of-art that imposes an affirmative obligation on IG to make reasonable efforts to minimize costs to consumers or risk being in violation of the SNG Contract.

Having considered the evidence presented concerning CO₂ risks and potential economic implications, we find the SNG Contract recognizes the risk associated with CO₂ and its potential regulation. The SNG Contract implements a reasonable strategy to limit cost exposure related to potential CO₂ regulation and capture and share the economic benefits of that regulation. Thus, the Commission is persuaded that the SNG Contract will be beneficial for retail end use customers when considered in a context, which includes CO₂ regulatory uncertainty.

i. **Conclusion.** All parties to this Cause expect that natural gas market prices will periodically be lower than the SNG Contract price. This circumstance exists because the future path of natural gas prices, the primary determinant in this comparison, can not be known with certainty, which is a primary rationale for the SNG Statute and the resulting SNG Contract. The Legislature understood the volatility and uncertain future of market prices of natural gas made the rate (or timing) and amount of savings uncertain. The Commission notes the SNG Statute does not define "guarantee of savings" and is silent as to when the guarantee of savings must occur—during the thirty-year term of the SNG Contract or outside of its term.

Having considered the evidence presented and the applicable law, the Commission finds the provisions within the SNG Contract sufficiently meet the SNG Statute's requirement for a guarantee of savings. The SNG Contract contains an assurance (or promise) by IG that end use gas customers will receive a net savings of \$100 million in 2008 real dollars. If the guarantee occurs outside of the thirty-year term of the Contract, the evidence shows this assurance is backed by sufficient collateral and other appropriate remedies to enable fulfillment of the guarantee of savings under the SNG Statute. The remedies and collateral backing the guarantee in the SNG Contract include:

- 1) Initial cash funding of the CPR account in an amount that is 150% of the guaranteed amount;
- 2) The opportunity for consumers to receive a reduction in the SNG price beginning in year twenty-six of the Contract (that would be worth over \$100 million per year to consumers for the last 3.5 years of the term) if the value of the SNG Facility as assessed at that time is not sufficient to cover any negative amount in the savings tracking account;

- 3) The opportunity for the Authority to elect to continue to receive SNG after the end of the term at a price reduction that is worth over \$120 million per year; and
- 4) The right of the Authority to force a sale of the SNG Facility that has an appraised value at the end of the term of \$1.8 billion in real dollars and \$4.5 billion in nominal dollars.

The collateral value of the four elements listed above exceeds \$2 billion in 2008 dollars, and we find this collateral more than adequate in relation to the expected values of reasonable downside scenarios of consumer savings, as discussed previously. The provisions of the SNG Contract, as well as the collateral value supporting the guarantee, provide secured assurances that are novel, unprecedented consumer protections, and support the Commission's finding that the SNG Contract provides a guarantee of savings consistent with the requirements of the SNG Statute. Moreover, as OUCC witness Mr. Miller points out, the SNG Contract provides Indiana customers with diversification of their energy supply; limitation regarding the possible risk of paying more for SNG than the market price of conventional natural gas supply as a result of the \$100 million in guaranteed savings; and protection against an obligation to purchase SNG without assurance of the availability of SNG supplies.

Although the risk under the SNG Contract is assigned primarily to ratepayers, the \$100 million in savings outweighs this risk. The Commission also notes the risk associated with the construction of the SNG Plant is primarily borne by IG, not Indiana ratepayers. Additionally, the \$100 million in savings guaranteed to ratepayers makes the SNG price reasonable regardless of the price of natural gas, and IG will post \$150 million in the CPR to minimize the impact of any possible losses experienced by ratepayers over the term of the SNG Contract. Accordingly, the Commission finds the SNG Contract is in the public interest and should be approved.

B. Public Utility Status and Declination of Jurisdiction. Indiana Code § 4-4-11.6-23 provides that the Authority is not considered an energy utility and is not subject to the jurisdiction of the Commission except as provided by the SNG Statute. The SNG Statute requires the Authority to submit the SNG Contract for Commission approval. The SNG Statute does not address the public utility status of IG, and IG asks the Commission to decline to exercise our jurisdiction over it pursuant to Indiana Code § 8-1-2.5-5. Before the Commission can consider IG's request to decline our jurisdiction over it, we must first determine whether IG is a public utility under Indiana Code § 8-1-8.5-1 and Indiana Code § 8-1-2-1. The Commission must then determine whether a certificate of public convenience and necessity ("CPCN") should be issued to IG for the construction of the SNG Facility pursuant to Indiana Code § 8-1-8.5-2.

1. Public Utility Status. According to the evidence presented, IG will produce SNG and incidentally produce electricity as a result of its production of SNG. With respect to its production of SNG, the evidence of record indicates the Authority will purchase and take title to the SNG. Ms. Alvey explains that the Authority intends to contract with a gas marketer to transport the gas to end-use consumers. However, regardless of its use of a marketer, the Authority will always take title to the SNG. Accordingly, IG is not a public utility pursuant to Indiana Code § 8-1-2-87.5. Nevertheless, the Commission notes that pursuant to Indiana Code §

8-1-2-87.6, IG is not subject to Indiana Code ch. 8-1-2.

With respect to the production of electricity, if the Commission finds the evidence indicates that IG is a public utility for purposes of Indiana's utility power plant construction law, Indiana Code § 8-1-8.5-1,¹¹ IG would also be an energy utility pursuant to Indiana Code § 8-1-2.5-2. The evidence establishes that IG is a limited liability company that will generate electricity, some of which may be used by Indiana residents. IG's ownership, development, financing, construction, and operation of the SNG Facility are primarily for the sale of SNG to the Authority or a third-party. Electricity will incidentally be generated as a result of the production of SNG. According to IG, it will sell the electricity wholesale to Indiana public utilities. Thus, with respect to the production and sale of electricity, the Commission finds IG is a public utility pursuant to Indiana Code § 8-1-8.5-1 and Indiana Code § 8-1-2-1. *E.g.*, *Sugar Creek Energy, LLC*, Cause No. 41753, p. 5 (IURC Feb. 23, 2001); *PSEG Lawrenceburg Energy Co.*, Cause No. 41757, 2000 Ind. PUC LEXIS 512, at *12 (IURC Dec. 20, 2000); *Benton County Wind Farm, LLC*, Cause No. 43068, 2006 Ind. PUC LEXIS 364, at *5-*6 (IURC Dec. 6, 2006). The Commission, therefore, has jurisdiction over IG with respect to its provision of electricity.

2. Declination of Jurisdiction. Since, as we previously determined, IG is a public utility pursuant to Indiana Code § 8-1-8.5-1 and Indiana Code § 8-1-2-1, IG is an "energy utility" as defined by Indiana Code § 8-1-2.5-2.¹² Therefore, we have jurisdiction over IG with respect to its provision of electricity. The Commission may decline to exercise its jurisdiction, in whole or in part, over an energy utility pursuant to Indiana Code § 8-1-2.5-5(a) if the Commission determines the public interest requires us to do so. Indiana Code § 8-1-2.5-5(b) states,

(b) In determining whether the public interest will be served, the commission shall consider the following:

(1) Whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful.

(2) Whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state.

(3) Whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency.

(4) Whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

¹¹Indiana Code § 8-1-8.5-1(a) defines "public utility" to mean a "(1) Public, municipally owned, or cooperatively owned utility; or (2) Joint agency created under IC 8-1-2.2."

¹² Indiana Code § 8-1-2.5-2 defines "energy utility" as "a public utility or municipally owned utility within the meaning of IC § 8-1-2-1"

The evidence in this Cause demonstrates that IG does not intend, nor does it request authority, to sell the electricity generated by the SNG Facility to the general public or to any retail customer. Instead, the incidentally generated electricity will be sold for resale subject to the jurisdiction of FERC under the provisions of the Federal Power Act. IG does not seek authority to exercise certain of the rights, powers, or privileges of an Indiana public utility in the construction and operation of the SNG Facility, including the power of eminent domain, and the exemption from zoning and land use regulation. Further, the costs of the SNG Facility will not be recovered through a rate base/rate of return or other process typically associated with public utility rates.

Accordingly, the Commission finds the exercise of our full jurisdiction over IG, in addition to FERC's jurisdiction, to be unnecessary and inefficient. The declination of our jurisdiction will benefit the utility and its customers by reducing the costs associated with the Commission's regulation of utilities. As a result of the reduced costs, IG will be in a better position to compete with similar electric utilities. However, the Commission finds our jurisdiction should be declined only in part.

The Commission has previously found in this Order that the provision in the Contract relating to the SNG Facility as collateral provides sufficient support for the guarantee of savings. We also recognize, as Mr. Kerney notes, that the lenders of the SNG Facility's debt capital would have first rights on the SNG Facility's sale proceeds, if there are any, to meet a mortgage. Therefore, it seems reasonable that we take steps to monitor any future related financing arrangements.

We find that the Authority or IG should provide written notice to the Commission of any transfers of ownership of the SNG Facility or ownership interest in the SNG Project including, but not limited to, (1) the grant of a security interest to a bank or other lender or collateral agent, administrative agent or other security representative, or a trustee on behalf of bond holders in connection with any financing or refinancing (including any lease financing); (2) a debtor in possession; or (3) a foreclosure (or deed in lieu of foreclosure) on the SNG Facility. Notice shall be provided to the Commission within thirty days of the transfer.¹³ The Commission shall also retain authority under Section 201 of the Federal Power Act to examine IG's books, accounts, memoranda, contracts and other records consistent with the limitations contained therein. 16 U.S.C. § 824 (2005). Further, the Commission finds IG and/or the Authority shall be subject to the reporting requirements discussed below.

C. CPCN. IG seeks a CPCN for the SNG Facility to receive a tax credit pursuant to Indiana Code § 6-3.1-29-19. In order to receive the tax credit, Indiana Code § 6-3.1-29-19(a)(8)(A) requires IG to receive from the Commission a determination under Indiana Code § 8-1-8.5-2 that the public convenience and necessity require the construction of the SNG Plant. When considering whether to issue a CPCN to IG pursuant to Indiana Code ch. 8-1-8.5, the Commission must take into account certain considerations. Indiana Code § 8-1-8.5-5 sets forth specific findings the Commission must make in order to approve and grant a CPCN. First, the

¹³ Indiana Code § 8-1-2.5-7 provides the Commission with the ability to ensure that such financing activities are consistent with the declination of jurisdiction granted in this Order.

Commission must make a finding, based on the evidence of the record, as to the best estimate of construction costs. Second, the Commission must find that either (a) construction will be consistent with the Commission's plan, if any, for the expansion of electric generation facilities, or (b) the proposed construction is consistent with a utility-specific proposal as to the future needs of consumers in the state of Indiana or in the petitioning public utility's service area. Third, the Commission must find that public convenience and necessity require the facilities for which the CPCN is requested. Fourth, if the facility is to consume coal, the Commission must make a finding that the facility will use Indiana coal, or is justified using non-Indiana coal for governmental or economic reasons.

1. **Cost Estimate.** According to the evidence of record, Black & Veatch provided technical support for the SNG Project for approximately five years, including cost studies. Black & Veatch developed preliminary plant design information for the SNG Facility to support Leucadia's DOE Loan Guarantee Application and subsequent NEPA evaluation. In 2009 and 2010, Black & Veatch performed a FEED Study for Leucadia's Chicago Clean Energy ("CCE") Coal and Coke Gasification Project using the same technology and plant configuration planned for the SNG Project. In 2010, Black & Veatch provided preliminary design data for development of air emission and water discharge permit applications for the SNG Project. Black & Veatch also updated IG preliminary performance estimates, material balances, steam balances, and water balances incorporating CCE FEED Study data for three feedstock cases: 100% coal, 85% coal/balance coke, and 51% coal/balance coke. Based on Black & Veatch's technical support, Mr. Maley states the estimated construction cost to be over \$2.5 billion. Thus, based on the evidence of record, the Commission finds the estimate of construction costs to be approximately \$2.5 billion.

2. **Consistency with Commission or Utility-Specific Plan.** The SNG Facility produces SNG and electricity as a byproduct of the production of SNG. As noted above, the net electricity production available for sale is incidental to the production of SNG and at a nominal amount of 13 MW, which is a level not expected to affect the wholesale electricity market. IG does not have an electric service Integrated Resource Plan, and it has no retail customer service obligation. Further, because of the prototypical and innovative nature of the SNG Facility, there is no applicable Commission plan concerning its construction.

Nevertheless, we recognize the Legislature determined pursuant to its findings at Indiana Code § 4-4-11.6-12 that the availability of SNG would provide a reliable, reasonably priced, long-term energy supply, thus benefiting retail end-use customers in Indiana. The Legislature encouraged the construction of an SNG facility through low-cost financing, and the construction of the SNG Facility proposed here would fulfill the Legislature's intent concerning energy facilities and the provision of service in Indiana. Accordingly, the Commission finds the construction of the SNG Facility to be consistent with the Legislature's desire for the construction of such facility.

3. **Public Convenience and Necessity.** According to the evidence presented, IG has considered connections with other utilities in Indiana to facilitate the transmission and sale of the electricity. As noted previously, the SNG Facility is innovative and prototypical; there is no other SNG facility in the United States like the one proposed for

construction in Indiana by IG. Thus, the consideration of pooling agreements, the purchase of power, and the consideration of other methods of providing reliable, efficient, and economical electric service is unnecessary.

The Commission is aware, however, that the SNG Facility will have significant environmental benefits when compared to traditional electric generation. Pollutant emissions, such as SO₂, will be low. The ability to capture pollutant emissions will not increase the cost of the SNG Facility, like the add-ons (e.g., scrubbers) used with conventional generation facilities. In addition, the production of electricity should contribute to extending the life of existing generation facilities. The ability to prolong the need to construct new electric generation and install add-ons to existing generation facilities in Indiana will contribute to the provision of economical electric service. Further, the SNG Facility will provide for the diversification of natural gas production, which, as we found previously, will benefit Indiana ratepayers by mitigating gas price volatility.

The Commission also notes the economic development implications of the construction of the SNG Facility. According to Ms. Alvey, the investment value of the SNG Facility is expected to be \$2.5 billion. In addition, 200 people are expected to be employed at an average annual compensation of over \$70,000. If the price of Indiana coal is competitive, 300 jobs may be created in the Indiana coal industry.

Based on the evidence presented, the Commission finds the public convenience and necessity require the construction of the SNG Facility.

4. Coal Supply. Mr. Weiss states Indiana has significant coal reserves, which are sufficient to supply the SNG Facility for decades. The SNG Project is expected to use Indiana coal as its primary feedstock unless economic considerations or other governmental requirements justify utilization of non-Indiana coal or other feedstock. IG selected the Ohio River location for the SNG Facility to increase its fuel supply options (truck, barge, or rail). Thus, if Indiana coal, because of governmental or economic considerations, is not the best fuel supply option, the Ohio River location allows IG to negotiate competitive fuel supply contracts from multiple sources, including the Illinois Basin. Mr. Maley testifies, however, that IG is incented to use Indiana coal to minimize transportation costs and receive tax credits. Mr. Ulrey notes the potential benefits concerning the SNG Contract. The benefits include the likely use of Illinois Basin coal, and thus Indiana coal, and Indiana economic growth through jobs for construction, maintenance and operations, and possible coal jobs.

Based on the evidence presented, the Commission finds the SNG Facility will utilize Indiana coal. Moreover, if economic or governmental considerations require the use of non-Indiana coal, IG is justified in doing so.

5. Conclusion. The Commission finds that pursuant to Indiana Code § 8-1-8.5-2, the public convenience and necessity require, or will require, the construction of the SNG Facility.

D. Reporting Requirements. It shall be a condition of this Order that Joint

Petitioners file reports with the Commission as provided by Indiana Code § 8-1-2-49. Further, Joint Petitioners are required to provide such other information as the Commission may from time to time request. A responsible officer of Joint Petitioners furnishing any such report shall verify the report and provide two paper copies and one electronic copy within the timeframes prescribed herein. These reports shall include the following:

1. **Initial Reports.** Joint Petitioners will furnish the following information:

1. Name, title, address, and phone number(s) for primary contact person(s) at the SNG Facility within one year of this Order and shall update the information to the extent it changes.
2. Copy of any Interconnection System Impact Studies prepared by the Midwest ISO or PJM;
3. Connecting utilities for electricity when established;
4. A copy of the final air and water permits, within ten days of receipt;
5. Notification of receipt of the conditional commitment for the Federal Loan Guarantee or the DOE Guaranteed Financing within ten days of receipt;
6. Commencing twelve months prior to the expected Commercial Production Date, written notice every month of the date on which the Commercial Production Date is projected by Seller to occur (based on Seller's most recent projections as of each such notice);
7. A copy of interconnect agreement(s) with the interstate natural gas pipeline(s) that will be the Receiving Pipeline(s) under the SNG Contract, within ten days of completion;
8. Copies of all the gas management, distribution, and transportation arrangements required to be completed by Buyer under the SNG Contract, within ten days of completion;
9. Date of Financial Closing and Construction Commencement for the SNG Facility; and
10. The occurrence of the Commercial Production Date as defined in the SNG Contract.

2. **Annual Report.** Joint Petitioners will furnish annual reports beginning one year from the Commercial Production Date that shall provide, to the extent such information is known, the following:

1. Any changes of the information provided in the Initial Reports;

2. A description of the mix of coal and petroleum coke used during the prior twelve-month period;
3. A description of contingency plans (if any) detailing response plans to emergency conditions as required by state and local governments; and
4. An accounting of the balance in the Cumulative Real Contract Savings Tracking Account.

The reports required by this Order shall be filed within thirty days of the end of each calendar quarter following the issuance of this Order until the quarter that occurs after commercial operation of the SNG Facility is achieved. Any report specifically required following that quarter and until the due date of the next Annual Report should be filed as an addendum to Petitioner's Annual Report.

E. Utility Management Agreement. Indiana Code § 4-4-11.6-15 states, "The authority may enter into management and related contracts as needed to transport, store, deliver, manage, and bill and collect for the delivery and sale of SNG to retail end use customers." Indiana Code § 4-4-11.6-22 states:

(a) Upon the request of the authority, the commission shall order a regulated energy utility to enter into a management contract with the authority to:

- (1) distribute and deliver SNG purchased by the authority; and
- (2) provide billing, collection, and other services related to the purchase, distribution, and delivery of the SNG.

(b) A management contract entered into under subsection (a) must include a mechanism by which the regulated energy utility is reimbursed for all costs incurred in performing the management contract in excess of costs that, as determined by the commission, the regulated energy utility would otherwise have incurred in the ordinary course of business.

Under Indiana Code § 4-4-11.6-22, the Commission shall order the regulated energy utilities into UMAs with the Authority only if the Authority asks the Commission to do so. The Authority, pursuant to the Joint Petition, requests the Commission to, "if necessary, order Indiana regulated gas distribution energy utilities to enter into [UMAs] with the Authority" Instead of asking the Commission to order the utilities into UMAs pursuant to Indiana Code § 4-4-11.6-22, the Authority asks us to determine if it is necessary for the Commission to order the regulated energy utilities into UMAs. Thus, the Commission declines at this time to order the utilities into UMAs.

The Commission notes certain parties express concern with respect to the terms of the UMAs. Mr. Frank Shambo, for example, testifies concerning the implications of UMAs on the NIPSCO LDCs. He states the NIPSCO LDCs are concerned that while the proposed form of UMA identifies a non-exclusive list of costs that could be considered by an LDC as being specific to the SNG Project, the UMA is not fully clear regarding the specific mechanics for recovering such costs by the utilities. He testifies the mechanics for recovery of utility-incurred

incremental costs would best be determined in a technical conference noticed and convened by the Commission. He testifies that if the terms and provisions of the UMA are clarified or administered through a Commission-noticed technical conference following approval of the SNG Contract, all LDCs can be assured that the allocation methodology, the definition of incremental costs, the formula for inclusion of such costs and the LDCs' quarterly gas cost adjustments, and the definition of customers who are exempt from SNG price adjustments and credits are fair and balanced.

Mr. Ulrey testifies that IG should not be a third-party beneficiary of the UMAs and allowed to enforce the Authority's rights under the UMAs. The Vectren Energy LDCs are agreeable to the technical conference as suggested by Mr. Shambo.

The Commission encourages the parties to resolve issues related to the UMAs among themselves. The parties should convene meetings to discuss and resolve issues concerning the UMAs. If the parties are unable to reach an agreement, the Authority should file a petition in a separately docketed proceeding with the Commission asking us to order the utilities to enter into the UMAs pursuant to Indiana Code § 4-4-11.6-22. Disputes concerning the UMAs may be resolved in the separately docketed proceeding.

F. Confidential Treatment of Certain Information. On February 17, 2011, Joint Petitioner IFA filed its Application for Confidential Treatment of the Final Report of Shaw Consultants International, Inc. On March 24, 2011, the Six LDCs filed a Motion for Protective Order of certain Confidential Information derived from a financial model prepared, owned, and provided by IG pursuant to a Confidentiality Agreement. On March 23, 2011, Vectren Energy filed its Motion for Protective Order seeking confidential treatment of certain information provided by IG pursuant to Confidentiality Agreements. On March 28, 2011, Vectren Energy filed its Second Motion for Protective Order.

With regard to each of the above motions for protective order, the Presiding Officers made preliminary findings of confidentiality on the basis that the information sought to be protected in each of motions is trade secret as defined in Indiana Code § 24-2-3-2. The Presiding Officers determined that the confidential information should be treated as confidential pursuant to Indiana Code § 5-14-3-4, and confidential procedures should be followed with respect to this information.

In addition, on May 5, 2011, Vectren Energy cross-examined Mr. Maley and offered into the record Vectren Energy's CX-3 and Vectren CX-4. IG argued that the information contained in the exhibits constitutes, or is derived from, confidential proprietary trade secrets, which was provided to Vectren Energy under a Confidentiality Agreement. After hearing argument of counsel, the Presiding Officers preliminarily determined Vectren Energy's Exhibits CX-3 and CX-4 constitute competitively sensitive confidential trade-secret economic data and pricing information derived from IG's financial models that should be protected from public disclosure.

The Commission finds that the information preliminarily determined to be confidential trade secret should continue to be held confidential by the Commission in accordance with the requirements of Indiana Code §§ 5-14-3-3, 8-1-2-29, and 24-2-3-1 and shall continue to be held

as confidential by the Commission.

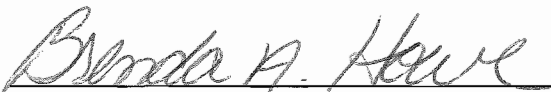
IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The SNG Contract is hereby approved.
2. IG is hereby determined to be a “public utility” within the meaning of Indiana Code § 8-1-8.5-1 and Indiana Code § 8-1-2-1 and an “energy utility” within the meaning of Indiana Code § 8-1-2.5-2 for purposes of the generation of electricity.
3. The Commission declines to exercise its jurisdiction over IG and its construction, ownership, operation and financing of the SNG Facility except as specifically stated within this Order.
4. IG is granted a CPCN pursuant to Indiana Code ch. 8-1-8.5.
5. The information preliminarily determined to be confidential trade secret should continue to be held confidential by the Commission in accordance with the requirements of Indiana Code §§ 5-14-3-3, 8-1-2-29, and 24-2-3-1 and shall continue to be held as confidential by the Commission.
6. IG shall not sell at retail in the state of Indiana any of the SNG or electricity produced by the SNG Project without further Order of the Commission.
7. Joint Petitioners shall comply fully with the terms of this Order and submit to the Commission all information required by the terms of this Order.
8. This Order shall be effective on and after the date of its approval.

ATTERHOLT, LANDIS AND ZIEGNER CONCUR; MAYS AND BENNETT NOT PARTICIPATING:

APPROVED: NOV 22 2011

**I hereby certify that the above is a true
and correct copy of the Order as approved.**



**Brenda A. Howe
Secretary to the Commission**